

for process interdependencies. The automated process is based on a drilling simulator, the process representing a highly interactive process which is encompassed in a software system that: (1) allows well construction practices to be tightly linked to geological and geomechanical models, (2) enables asset teams to plan realistic well trajectories by automatically generating cost estimates with a risk assessment, thereby allowing quick screening and economic evaluation of prospects, (3) enables asset teams to quantify the value of additional information by providing insight into the business impact of project uncertainties, (4) reduces the time required for drilling engineers to assess risks and create probabilistic time and cost estimates faithful to an engineered well design, (5) permits drilling engineers to immediately assess the business impact and associated risks of applying new technologies, new procedures, or different approaches to a well design. Discussion of these points illustrate the application of the workflow and verify the value, speed, and accuracy of this integrated well planning and decision-support tool.

[005] Designing a drillstring is not terribly complex, but is very tedious. The sheer number of components, methods, and calculations required to ensure the mechanical suitability of stacking one component on top of another component is quite cumbersome. Add to this fact that a different drillstring is created for every hole section and often every different bit run in the drilling of a well and the amount of work involved can be large and prone to human error.

SUMMARY OF THE INVENTION

[006] One aspect of the present invention involves a method of generating drillstring design information in response to input data including wellbore geometry and wellbore trajectory requirements, comprising the steps of: generating a summary of a drillstring in each hole section of a wellbore in response to the input data.

[007] Another aspect of the present invention involves a program storage device readable by a machine tangibly embodying a program of instructions executable by the machine to perform method steps for generating drillstring design information in response to input data including wellbore geometry and wellbore trajectory requirements, the method steps comprising: generating a summary of a drillstring in each hole section of a wellbore in response to the input data.

[008] Another aspect of the present invention involves a method of generating and recording or displaying drillstring design output data associated with a drillstring in a wellbore in response to input data including wellbore geometry and wellbore trajectory requirements, comprising the steps of: generating a summary of the drillstring in each hole section of a wellbore in response to the input data, the summary of the drillstring in each hole section of the wellbore being selected from a group consisting of: an outer diameter of a first drill collar of the drillstring, an outer diameter of a second drill collar of the drillstring, an outer diameter of a heavy weight of the drillstring, an outer diameter of a drill pipe of the drillstring, a maximum weight of a weight-on-bit in each hole section of the drill string, a weight of a first drill collar of the drillstring, a weight of a second drill collar of the drillstring, a weight of a heavy weight of the drillstring, a length of a first drill collar of the drillstring, a length of a second drill collar of the drillstring, a length of a heavy weight of the drillstring, a length of a drill pipe of the drillstring, a tensile risk of the drillstring, a cost figure associated with the drillstring, and a kick tolerance associated with the drillstring; and recording or displaying the summary of the drill string in the each hole section of the wellbore.

[009] Another aspect of the present invention involves a program storage device readable by a machine tangibly embodying a program of instructions executable by the machine to perform method steps for generating and recording or displaying drillstring design output data associated with a drillstring in a wellbore in response to input data including wellbore geometry and wellbore trajectory requirements, the method steps comprising: generating a summary of the drillstring in each hole section of a wellbore in response to the input data, the summary of the drillstring in each hole section of the wellbore being selected from a group consisting of: an outer diameter of a first drill collar of the drillstring, an outer diameter of a second drill collar of the drillstring, an outer diameter of a heavy weight of the drillstring, an outer diameter of a drill pipe of the drillstring, a maximum weight of a weight-on-bit in each hole section of the drill string, a weight of a first drill collar of the drillstring, a weight of a second drill collar of the drillstring, a weight of a heavy weight of the drillstring, a length of a first drill collar of the drillstring, a length of a second drill collar of the drillstring, a length of a heavy weight of the drillstring, a length of a drill pipe of the drillstring, a tensile risk of the drillstring, a cost figure associated with the drillstring, and a kick tolerance associated with the drillstring; and recording or displaying the summary of the drill string in the each hole section of the wellbore.

[0010] Another aspect of the present invention involves a system adapted for generating and recording or displaying drillstring design output data associated with a drillstring in a wellbore in response to input data including wellbore geometry and wellbore trajectory requirements, comprising: apparatus adapted for generating a summary of the drillstring in each hole section of a wellbore in response to the input data, the summary of the drillstring in each hole section of the wellbore being selected from a group consisting of: an outer diameter of a first drill collar of the drillstring, an outer diameter of a second drill collar of the drillstring, an outer diameter of a heavy weight of the drillstring, an outer diameter of a drill pipe of the drillstring, a maximum weight of a weight-on-bit in each hole section of the drill string, a weight of a first drill collar of the drillstring, a weight of

a second drill collar of the drillstring, a weight of a heavy weight of the drillstring, a length of a first drill collar of the drillstring, a length of a second drill collar of the drillstring, a length of a heavy weight of the drillstring, a length of a drill pipe of the drillstring, a tensile risk of the drillstring, a cost figure associated with the drillstring, and
5 a kick tolerance associated with the drillstring; and recorder or display apparatus adapted for recording or displaying the summary of the drill string in the each hole section of the wellbore.

[0011] Further scope of applicability of the present invention will become apparent
10 from the detailed description presented hereinafter. It should be understood, however, that the detailed description and the specific examples, while representing a preferred embodiment of the present invention, are given by way of illustration only, since various changes and modifications within the spirit and scope of the invention will become obvious to one skilled in the art from a reading of the following detailed description.

BRIEF DESCRIPTION OF THE DRAWINGS

[0012] A full understanding of the present invention will be obtained from the detailed
5 description of the preferred embodiment presented hereinbelow, and the accompanying
drawings, which are given by way of illustration only and are not intended to be limitative
of the present invention, and wherein:

[0013] figure 1 illustrates a software architecture schematic indicating a modular nature
10 to support custom workflows;

[0014] figure 2 including figures 2A, 2B, 2C, and 2D illustrates a typical task view
consisting of workflow, help and data canvases;

15 [0015] figure 3 including figures 3A, 3B, 3C, and 3D illustrates wellbore stability, mud
weights, and casing points;

[0016] figure 4 including figures 4A, 4B, 4C, and 4D illustrates risk assessment;

20 [0017] figure 5 including figures 5A, 5B, 5C, and 5D illustrates a Monte Carlo time and
cost distribution;

[0018] figure 6 including figures 6A, 6B, 6C, and 6D illustrates a probabilistic time and
cost vs. depth;

25 [0019] figure 7 including figures 7A, 7B, 7C, and 7D illustrates a summary montage;

[0020] figure 8 illustrates a workflow in an 'Automatic Well Planning Software
System';

[0021] figure 9A illustrates a computer system which stores an Automatic Well Planning Risk Assessment Software;

5 [0022] figure 9B illustrates a display as shown on a Recorder or Display device of the Computer System of figure 9A;

[0023] figure 10 illustrates a detailed construction of the Automatic Well Planning Risk Assessment Software stored in the Computer System of figure 9A;

10 [0024] figure 11 illustrates a block diagram representing a construction of the Automatic Well Planning Risk Assessment software of figure 10 which is stored in the Computer System of figure 9A;

15 [0025] figure 12 illustrates a Computer System which stores an Automatic Well Planning Bit Selection software;

[0026] figure 13 illustrates a detailed construction of the Automatic Well Planning Bit Selection Software stored in the Computer System of figure 12;

20 [0027] figures 14A and 14B illustrate block diagrams representing a functional operation of the Automatic Well Planning Bit Selection software of figure 13 of the present invention;

25 [0028] figure 15 including figures 15A, 15B, 15C, and 15D illustrates a Bit Selection display which is generated by a Recorder or Display device associated with the Computer System of figure 12 which stores the Automatic Well Planning Bit Selection software in accordance with the present invention;

30 [0029] figure 16 illustrates a Computer System which stores an Automatic Well Planning Drillstring Design software in accordance with the present invention;

[0030] figure 17 illustrates a detailed construction of the Automatic Well Planning Drillstring Design Software stored in the Computer System of figure 16 in accordance with the present invention;

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[0031] figure 18 illustrates a more detailed construction of the Automatic Well Planning Drillstring Design software system of figures 16 and 17 including the Drillstring Design Algorithms and Logical Expressions; and

10 [0032] figure 19 including figures 19A, 19B, 19C, and 19D illustrates a typical 'Drillstring Design output display' which can be recorded or displayed on the recorder or display device 62b in figure 16 and which displays the Drillstring Design Output Data 62b1 in figure 16.

DETAILED DESCRIPTION

[0033] An 'Automatic Well Planning Software System' is disclosed in this

5 specification. The 'Automatic Well Planning Software System' of the present invention is a "smart" tool for rapid creation of a detailed drilling operational plan that provides economics and risk analysis. The user inputs trajectory and earth properties parameters; the system uses this data and various catalogs to calculate and deliver an optimum well design thereby generating a plurality of outputs, such as drill string design, casing seats,
10 mud weights, bit selection and use, hydraulics, and the other essential factors for the drilling task. System tasks are arranged in a single workflow in which the output of one task is included as input to the next. The user can modify most outputs, which permits fine-tuning of the input values for the next task. The 'Automatic Well Planning Software System' has two primary user groups: (1) Geoscientist: Works with trajectory and earth
15 properties data; the 'Automatic Well Planning Software System' provides the necessary drilling engineering calculations; this allows the user to scope drilling candidates rapidly in terms of time, costs, and risks; and (2) Drilling engineer: Works with wellbore geometry and drilling parameter outputs to achieve optimum activity plan and risk assessment; Geoscientists typically provide the trajectory and earth properties data. The
20 scenario, which consists of the entire process and its output, can be exported for sharing with other users for peer review or as a communication tool to facilitate project management between office and field. Variations on a scenario can be created for use in business decisions. The 'Automatic Well Planning Software System' can also be used as a training tool for geoscientists and drilling engineers.

25 [0034] The 'Automatic Well Planning Software System' will enable the entire well construction workflow to be run through quickly. In addition, the 'Automatic Well Planning Software System' can ultimately be updated and re-run in a time-frame that supports operational decision making. The entire replanning process must be fast enough
30 to allow users to rapidly iterate to refine well plans through a series of what-if scenarios.

[0035] The decision support algorithms provided by the 'Automatic Well Planning Software System' disclosed in this specification would link geological and geomechanical data with the drilling process (casing points, casing design, cement, mud, bits, hydraulics, etc) to produce estimates and a breakdown of the well time, costs, and risks. This will allow interpretation variations, changes, and updates of the Earth Model to be quickly propagated through the well planning process.

[0036] The software associated with the aforementioned 'Automatic Well Planning Software System' accelerates the prospect selection, screening, ranking, and well construction workflows. The target audiences are two fold: those who generate drilling prospects, and those who plan and drill those prospects. More specifically, the target audiences include: Asset Managers, Asset Teams (Geologists, Geophysicists, Reservoir Engineers, and Production Engineers), Drilling Managers, and Drilling Engineers.

[0037] Asset Teams will use the software associated with the 'Automatic Well Planning Software System' as a scoping tool for cost estimates, and assessing mechanical feasibility, so that target selection and well placement decisions can be made more knowledgeably, and more efficiently. This process will encourage improved subsurface evaluation and provide a better appreciation of risk and target accessibility. Since the system can be configured to adhere to company or local design standards, guidelines, and operational practices, users will be confident that well plans are technically sound.

[0038] Drilling Engineers will use the software associated with the 'Automatic Well Planning Software System' disclosed in this specification for rapid scenario planning, risk identification, and well plan optimization. It will also be used for training, in planning centers, universities, and for looking at the drilling of specific wells, electronically drilling the well, scenario modeling and 'what-if' exercises, prediction and diagnosis of events, post-drilling review and knowledge transfer.

[0039] The software associated with the 'Automatic Well Planning Software System' will enable specialists and vendors to demonstrate differentiation amongst new or competing technologies. It will allow operators to quantify the risk and business impact of the application of these new technologies or procedures.

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[0040] Therefore, the 'Automatic Well Planning Software System' disclosed in this specification will: (1) dramatically improve the efficiency of the well planning and drilling processes by incorporating all available data and well engineering processes in a single predictive well construction model, (2) integrate predictive models and analytical

10 solutions for wellbore stability, mud weights & casing seat selection, tubular & hole size selection, tubular design, cementing, drilling fluids, bit selection, rate of penetration, BHA design, drillstring design, hydraulics, risk identification, operations planning, and probabilistic time and cost estimation, all within the framework of a mechanical earth model, (3) easily and interactively manipulate variables and intermediate results within individual scenarios to produce sensitivity analyses. As a result, when the 'Automatic Well Planning Software System' is utilized, the following results will be achieved: (1) more accurate results, (2) more effective use of engineering resources, (3) increased awareness, (4) reduced risks while drilling, (5) decreased well costs, and (6) a standard methodology or process for optimization through iteration in planning and execution. As a result, during the implementation of the 'Automatic Well Planning Software System' of the present invention, the emphasis was placed on architecture and usability.

[0041] In connection with the implementation of the 'Automatic Well Planning Software System', the software development effort was driven by the requirements of a flexible architecture which must permit the integration of existing algorithms and technologies with commercial-off-the-shelf (COTS) tools for data visualization. Additionally, the workflow demanded that the product be portable, lightweight and fast, and require a very small learning curve for users. Another key requirement was the ability to customize the workflow and configuration based on proposed usage, user profile and equipment availability.

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[0042] The software associated with the 'Automatic Well Planning Software System' was developed using the 'Ocean' framework owned by Schlumberger Technology Corporation of Houston, Texas. This framework uses Microsoft's .NET technologies to provide a software development platform which allows for easy integration of COTS software tools with a flexible architecture that was specifically designed to support custom workflows based on existing drilling algorithms and technologies.

[0043] Referring to figure 1, a software architecture schematic is illustrated indicating the 'modular nature' for supporting custom workflows. Figure 1 schematically shows the modular architecture that was developed to support custom workflows. This provides the ability to configure the application based on the desired usage. For a quick estimation of the time, cost and risk associated with the well, a workflow consisting of lookup tables and simple algorithms can be selected. For a more detailed analysis, complex algorithms can be included in the workflow.

[0044] In addition to customizing the workflow, the software associated with the 'Automatic Well Planning Software System' was designed to use user-specified equipment catalogs for its analysis. This ensures that any results produced by the software are always based on local best practices and available equipment at the project site. From a usability perspective, application user interfaces were designed to allow the user to navigate through the workflow with ease.

[0045] Referring to figure 2, a typical task view consisting of workflow, help and data canvases is illustrated. Figure 2 shows a typical task view with its associated user canvases. A typical task view consists of a workflow task bar, a dynamically updating help canvas, and a combination of data canvases based on COTS tools like log graphics, Data Grids, Wellbore Schematic and charting tools. In any task, the user has the option to modify data through any of the canvases; the application then automatically synchronizes the data in the other canvases based on these user modifications.

[0046] The modular nature of the software architecture associated with the 'Automatic Well Planning Software System' also allows the setting-up of a non-graphical workflow, which is key to implementing advanced functionality, such as batch processing of an entire field, and sensitivity analysis based on key parameters, etc.

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[0047] Basic information for a scenario, typical of well header information for the well and wellsite, is captured in the first task. The trajectory (measured depth, inclination, and azimuth) is loaded and the other directional parameters like true vertical depth and dogleg severity are calculated automatically and graphically presented to the user.

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[0048] The 'Automatic Well Planning Software System' disclosed in this specification requires the loading of either geomechanical earth properties extracted from an earth model, or, at a minimum, pore pressure, fracture gradient, and unconfined compressive strength. From this input data, the 'Automatic Well Planning Software System'

15 automatically selects the most appropriate rig and associated properties, costs, and mechanical capabilities. The rig properties include parameters like derrick rating to evaluate risks when running heavy casing strings, pump characteristics for the hydraulics, size of the BOP, which influences the sizes of the casings, and very importantly the daily rig rate and spread rate. The user can select a different rig than what the 'Automatic Well
20 Planning Software System' proposed and can modify any of the technical specifications suggested by the software.

[0049] Other wellbore stability algorithms (which are offered by Schlumberger Technology Corporation, or Houston, Texas) calculate the predicted shear failure and the
25 fracture pressure as a function of depth and display these values with the pore pressure. The 'Automatic Well Planning Software System' then proposes automatically the casing seats and maximum mud weight per hole section using customizable logic and rules. The rules include safety margins to the pore pressure and fracture gradient, minimum and maximum lengths for hole sections and limits for maximum overbalance of the drilling
30 fluid to the pore pressure before a setting an additional casing point. The 'Automatic Well

Planning Software System' evaluates the casing seat selection from top-to-bottom and from bottom-to-top and determines the most economic variant. The user can change, insert, or delete casing points at any time, which will reflect in the risk, time, and cost for the well.

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[0050] Referring to figure 3, a display showing wellbore stability, mud weights, and casing points is illustrated.

[0051] The wellbore sizes are driven primarily by the production tubing size. The preceding casing and hole sizes are determined using clearance factors. The wellbore sizes can be restricted by additional constraints, such as logging requirements or platform slot size. Casing weights, grades, and connection types are automatically calculated using traditional biaxial design algorithms and simple load cases for burst, collapse and tension. The most cost effective solution is chosen when multiple suitable pipes are found in the extensive tubular catalog. Non-compliance with the minimum required design factors are highlighted to the user, pointing out that a manual change of the proposed design may be in order. The 'Automatic Well Planning Software System' allows full strings to be replaced with liners, in which case, the liner overlap and hanger cost are automatically suggested while all strings are redesigned as necessary to account for changes in load cases. The cement slurries and placement are automatically proposed by the 'Automatic Well Planning Software System'. The lead and tail cement tops, volumes, and densities are suggested. The cementing hydrostatic pressures are validated against fracture pressures, while allowing the user to modify the slurry interval tops, lengths, and densities. The cost is derived from the volume of the cement job and length of time required to place the cement.

[0052] The 'Automatic Well Planning Software System' proposes the proper drilling fluid type including rheology properties that are required for hydraulic calculations. A sophisticated scoring system ranks the appropriate fluid systems, based on operating environment, discharge legislation, temperature, fluid density, wellbore stability, wellbore

friction and cost. The system is proposing not more than 3 different fluid systems for a well, although the user can easily override the proposed fluid systems.

[0053] A new and novel algorithm used by the 'Automatic Well Planning Software System' selects appropriate bit types that are best suited to the anticipated rock strengths, hole sizes, and drilled intervals. For each bit candidate, the footage and bit life is determined by comparing the work required to drill the rock interval with the statistical work potential for that bit. The most economic bit is selected from all candidates by evaluating the cost per foot which takes into account the rig rate, bit cost, tripping time and drilling performance (ROP). Drilling parameters like string surface revolutions and weight on bit are proposed based on statistical or historical data.

[0054] In the 'Automatic Well Planning Software System', the bottom hole assembly (BHA) and drillstring is designed based on the required maximum weight on bit, inclination, directional trajectory and formation evaluation requirements in the hole section. The well trajectory influences the relative weight distribution between drill collars and heavy weight drill pipe. The BHA components are automatically selected based on the hole size, the internal diameter of the preceding casings, and bending stress ratios are calculated for each component size transition. Final kick tolerances for each hole section are also calculated as part of the risk analysis.

[0055] The minimum flow rate for hole cleaning is calculated using Luo's² and Moore's³ criteria considering the wellbore geometry, BHA configuration, fluid density and rheology, rock density, and ROP. The bit nozzles total flow area (TFA) are sized to maximize the standpipe pressure within the liner operating pressure envelopes. Pump liner sizes are selected based on the flow requirements for hole cleaning and corresponding circulating pressures. The Power Law rheology model is used to calculate the pressure drops through the circulating system, including the equivalent circulating density (ECD).

[0056] Referring to figure 4, a display showing 'Risk Assessment' is illustrated.

[0057] In figure 4, in the 'Automatic Well Planning Software System', drilling event 'risks' are quantified in a total of 54 risk categories of which the user can customize the risk thresholds. The risk categories are plotted as a function of depth and color coded to aid a quick visual interpretation of potential trouble spots. Further risk assessment is achieved by grouping these categories in the following categories: 'gains', 'losses', 'stuck pipe', and 'mechanical problems'. The total risk log curve can be displayed along the trajectory to correlate drilling risks with geological markers. Additional risk analysis views display the "actual risk" as a portion of the "potential risk" for each design task.

[0058] In the 'Automatic Well Planning Software System', a detailed operational activity plan is automatically assembled from customizable templates. The duration for each activity is calculated based on the engineered results of the previous tasks and Non-Productive Time (NPT) can be included. The activity plan specifies a range (minimum, average, and maximum) of time and cost for each activity and lists the operations sequentially as a function of depth and hole section. This information is graphically presented in the time vs depth and cost vs depth graphs.

[0059] Referring to figure 5, a display showing Monte Carlo time and cost distributions is illustrated. In figure 5, the 'Automatic Well Planning Software System' uses Monte Carlo simulation to reconcile all of the range of time and cost data to produce probabilistic time and cost distributions.

[0060] Referring to figure 6, a display showing Probabilistic time and cost vs. depth is illustrated. In figure 6, this probabilistic analysis, used by the 'Automatic Well Planning Software System' of the present invention, allows quantifying the P10, P50 and P90 probabilities for time and cost.

[0061] Referring to figure 7, a display showing a summary montage is illustrated. In figure 7, a comprehensive summary report and a montage display, utilized by the 'Automatic Well Planning Software System' of the present invention, can be printed or plotted in large scale and are also available as a standard result output.

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[0062] Using its expert system and logic, the 'Automatic Well Planning Software System' disclosed in this specification automatically proposes sound technical solutions and provides a smooth path through the well planning workflow. Graphical interaction with the results of each task allows the user to efficiently fine-tune the results. In just
10 minutes, asset teams, geoscientists, and drilling engineers can evaluate drilling projects and economics using probabilistic cost estimates based on solid engineering fundamentals instead of traditional, less rigorous estimation methods. The testing program combined with feedback received from other users of the program during the development of the software package made it possible to draw the following conclusions: (1) The 'Automatic
15 Well Planning Software System' can be installed and used by inexperienced users with a minimum amount of training and by referencing the documentation provided, (2) The need for good earth property data enhances the link to geological and geomechanical models and encourages improved subsurface interpretation; it can also be used to quantify the value of acquiring additional information to reduce uncertainty, (3) With a minimum
20 amount of input data, the 'Automatic Well Planning Software System' can create reasonable probabilistic time and cost estimates faithful to an engineered well design; based on the field test results, if the number of casing points and rig rates are accurate, the results will be within 20% of a fully engineered well design and AFE, (4) With additional customization and localization, predicted results compare to within 10% of a fully
25 engineered well design AFE, (5) Once the 'Automatic Well Planning Software System' has been localized, the ability to quickly run new scenarios and assess the business impact and associated risks of applying new technologies, procedures or approaches to well designs is readily possible, (6) The speed of the 'Automatic Well Planning Software System' allows quick iteration and refinement of well plans and creation of different
30 'what if' scenarios for sensitivity analysis, (7) The 'Automatic Well Planning Software

System' provides consistent and transparent well cost estimates to a process that has historically been arbitrary, inconsistent, and opaque; streamlining the workflow and eliminating human bias provides drilling staff the confidence to delegate and empower non-drilling staff to do their own scoping estimates, (8) The 'Automatic Well Planning Software System' provides unique understanding of drilling risk and uncertainty enabling more realistic economic modeling and improved decision making, (9) The risk assessment accurately identifies the type and location of risk in the wellbore enabling drilling engineers to focus their detailed engineering efforts most effectively, (10) It was possible to integrate and automate the well construction planning workflow based on an earth model and produce technically sound usable results, (11) The project was able to extensively use COTS technology to accelerate development of the software, and (12) The well engineering workflow interdependencies were able to be mapped and managed by the software.

[0063] The following nomenclature was used in this specification:

RT =	Real-Time, usually used in the context of real-time data (while drilling).
G&G =	Geological and Geophysical
SEM =	Shared Earth Model
MEM =	Mechanical Earth Model
NPT =	Non Productive Time, when operations are not planned, or due to operational difficulties, the progress of the well has be delayed, also often referred to as Trouble Time.
NOT =	Non Optimum Time, when operations take longer than they should for various reasons.
WOB =	Weight on bit
ROP =	Rate of penetration
RPM =	Revolutions per minute
BHA =	Bottom hole assembly
SMR =	Software Modification Request
BOD =	Basis of Design, document specifying the requirements for a well to be drilled.
AFE =	Authorization for Expenditure

References

(1) Booth, J., Bradford, I.D.R., Cook, J.M., Dowell, J.D., Ritchie, G., Tuddenham, I.: 'Meeting Future Drilling Planning and Decision Support Requirements: A New Drilling Simulator', IADC/SPE 67816 presented at the 2001 IADC/SPE Drilling Conference, Amsterdam, The Netherlands, 27 February – 1 March.

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(2) Luo, Y., Bern, P.A. and Chambers, B.D.: 'Flow-Rate Predictions for Cleaning Deviated Wells', paper IADC/SPE 23884 presented at the 1992 IADC/SPE Drilling Conference, New Orleans, Louisiana, February 18-21.

10 (3) Moore and Chien theory is published in 'Applied Drilling Engineering', Bourgoyne, A.T., Jr, et al., SPE Textbook Series Vol2.

[0064] A functional specification associated with the overall 'Automatic Well Planning Software System' (termed a 'use case') will be set forth in the following paragraphs. This

15 functional specification relates to the overall 'Automatic Well Planning Software System'.

[0065] The following defines information that pertains to this particular 'use case'.

Each piece of information is important in understanding the purpose behind the 'use

20 Case'.

Goal In Context:	Describe the full workflow for the low level user
Scope:	N/A
Level:	Low Level
Pre-Condition:	Geological targets pre-defined
Success End Condition:	Probability based time estimate with cost and risk
Failed End Condition:	Failure in calculations due to assumptions or if distribution of results is too large
Primary Actor:	Well Engineer
Trigger Event:	N/A

[0066] Main Success Scenario -- This Scenario describes the steps that are taken from trigger event to goal completion when everything works without failure. It also describes any required cleanup that is done after the goal has been reached. The steps are listed

25 below:

1. User opens program, and system prompts user whether to open an old file or create a new one. User creates new model and system prompts user for well information (well name, field, country, coordinates). System prompts user to insert earth model. Window with different options appears and user selects data level. Secondary window appears where file is loaded or data inserted manually. System displays 3D view of earth model with key horizons, targets, anti-targets, markers, seismic, etc.
2. System prompts user for a well trajectory. The user either loads from a file or creates one in Caviar for Swordfish. System generates 3D view of trajectory in the earth model and 2D views, both plan and vertical section. User prompted to verify trajectory and modify if needed via direct interaction with 3D window.
3. The system will extract mechanical earth properties (PP, FG, WBS, lithology, density, strength, min/max horizontal stress, etc.) for every point along the trajectory and store it. These properties will either come from a populated mechanical earth model, from interpreted logs applied to this trajectory, or manually entered.
4. The system will prompt the user for the rig constraints. Rig specification options will be offered and the user will choose either the type of rig and basic configurations or insert data manually for a specific drilling unit.
5. The system will prompt the user to enter pore pressure data, if applicable, otherwise taken from the mechanical earth model previously inserted and a MW window will be generated using PP, FG, and WBS curves. The MW window will be displayed and allow interactive modification.
6. The system will automatically divide the well into hole/casing sections based on kick tolerance and trajectory sections and then propose a mud weight schedule. These will be displayed on the MW window and allow the user to interactively modify their values. The casing points can also be interactively modified on the 2D and 3D trajectory displays
7. The system will prompt the user for casing size constraints (tubing size, surface slot size, evaluation requirements), and based on the number of sections generate

the appropriate hole size – casing size combinations. The hole/casing circle chart will be used, again allowing for interaction from the user to modify the hole/casing size progression.

- 5 8. The system will successively calculate casing grades, weights/wall thickness and connections based on the sizes selected and the depths. User will be able to interact and define availability of types of casing.
9. The system will generate a basic cementing program, with simple slurry designs and corresponding volumes..
- 10 10. The system will display the wellbore schematic based on the calculations previously performed and this interface will be fully interactive, allowing the user to click and drag hole & casing sizes, top & bottom setting depths, and recalculating based on these selections. System will flag user if the selection is not feasible.
11. The system will generate the appropriate mud types, corresponding rheology, and composition based on the lithology, previous calculations, and the users selection.
- 15 12. The system will successively split the well sections into bit runs, and based on the rock properties will select drilling bits for each section with ROP and drilling parameters.
13. The system will generate a basic BHA configuration, based on the bit section runs, trajectory and rock properties.
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Items 14, 15, and 16 represent one task: Hydraulics.

- 25 14. The system will run a hole cleaning calculation, based on trajectory, wellbore geometry, BHA composition and MW characteristics.
15. The system will do an initial hydraulics/ECD calculation using statistical ROP data. This data will be either selected or user defined by the system based on smart table lookup.

16. Using the data generated on the first hydraulics calculation, the system will perform an ROP simulation based on drilling bit characteristics and rock properties.
- 5 17. The system will run a successive hydraulics/ECD calculation using the ROP simulation data. System will flag user if parameters are not feasible.
18. The system will calculate the drilling parameters and display them on a multi display panel. This display will be exportable, portable, and printable.
- 10 19. The system will generate an activity planning sequence using default activity sequences for similar hole sections and end conditions. This sequence will be fully modifiable by the user, permitting modification in sequence order and duration of the event. This sequence will be in the same standard as the Well Operations or Drilling Reporting software and will be interchangeable with the Well Operations or Drilling Reporting software. The durations of activities will be populated from tables containing default "best practice" data or from historical data (DIMS, Snapper...).
- 15 20. The system will generate time vs. depth curve based on the activity planning details. The system will create a best, mean, and worst set of time curves using combinations of default and historical data. These curves will be exportable to other documents and printable.
- 20 21. The system will prompt the user to select probability points such as P10, P50, P90 and then run a Monte Carlo simulation to generate a probability distribution curve for the scenario highlighting the user selected reference points and corresponding values of time. The system will provide this as frequency data or cumulative probability curves. These curves will be again exportable and printable.
- 25 22. The system will generate a cost plan using default cost templates that are pre-configured by users and can be modified at this point. Many of the costs will reference durations of the entire well, hole sections, or specific activities to calculate the applied cost. The system will generate P10, P50, and P90 cost vs. depth curves.

23. The system will generate a summary of the well plan, in word format, along with the main display graphs. The user will select all that should be exported via a check box interface. The system will generate a large one-page summary of the whole process. This document will be as per a standard Well Operations Program template.

[0067] Referring to figure 8, as can be seen on the left side of the displays illustrated in figures 2 through 6, the 'Automatic Well Planning Software System' includes a plurality of tasks. Each of those tasks are illustrated in figure 8. In figure 8, those plurality of tasks are divided into four groups: (1) Input task 10, where input data is provided, (2) Wellbore Geometry task 12 and Drilling Parameters task 14, where calculations are performed, and (3) a Results task 16, where a set of results are calculated and presented to a user. The Input task 10 includes the following sub-tasks: (1) scenario information, (2) trajectory, (3) Earth properties, (4) Rig selection, (5) Resample Data. The Wellbore Geometry task 12 includes the following sub-tasks: (1) Wellbore stability, (2) Mud weights and casing points, (3) Wellbore sizes, (4) Casing design, (5) Cement design, (6) Wellbore geometry. The Drilling Parameters task 14 includes the following sub-tasks: (1) Drilling fluids, (2) Bit selection 14a, (3) Drillstring design 14b, (4) Hydraulics. The Results task 16 includes the following sub-tasks: (1) Risk Assessment 16a, (2) Risk Matrix, (3) Time and cost data, (4) Time and cost chart, (5) Monte Carlo, (6) Monte Carlo graph, (7) Summary report, and (8) montage.

[0068] Recalling that the Results task 16 of figure 8 includes a 'Risk Assessment' sub-task 16a, the 'Risk Assessment' sub-task 16a will be discussed in detail in the following paragraphs with reference to figures 9A, 9B, and 10.

Automatic Well Planning Software System – Risk Assessment sub-task 16a - Software

[0069] Identifying the risks associated with drilling a well is probably the most subjective process in well planning today. This is based on a person recognizing part of a

technical well design that is out of place relative to the earth properties or mechanical equipment to be used to drill the well. The identification of any risks is brought about by integrating all of the well, earth, and equipment information in the mind of a person and mentally sifting through all of the information, mapping the interdependencies, and based
5 solely on personal experience extracting which parts of the project pose what potential risks to the overall success of that project. This is tremendously sensitive to human bias, the individual's ability to remember and integrate all of the data in their mind, and the individuals experience to enable them to recognize the conditions that trigger each drilling risk. Most people are not equipped to do this and those that do are very
10 inconsistent unless strict process and checklists are followed. There are some drilling risk software systems in existence today, but they all require the same human process to identify and assess the likelihood of each individual risks and the consequences. They are simply a computer system for manually recording the results of the risk identification process.

15 [0070] The Risk Assessment sub-task 16a associated with the 'Automatic Well Planning Software System' of the present invention is a system that will automatically assess risks associated with the technical well design decisions in relation to the earth's geology and geomechanical properties and in relation to the mechanical limitations of the
20 equipment specified or recommended for use.

[0071] Risks are calculated in four ways: (1) by 'Individual Risk Parameters', (2) by 'Risk Categories', (3) by 'Total Risk', and (4) the calculation of 'Qualitative Risk Indices' for each.

25 [0072] Individual Risk Parameters are calculated along the measured depth of the well and color coded into high, medium, or low risk for display to the user. Each risk will identify to the user: an explanation of exactly what is the risk violation, and the value and the task in the workflow controlling the risk. These risks are calculated consistently and
30 transparently allowing users to see and understand all of the known risks and how they

are identified. These risks also tell the users which aspects of the well justify further engineering effort to investigate in more detail.

[0073] Group/category risks are calculated by incorporating all of the individual risks in specific combinations. Each individual risk is a member of one or more Risk Categories. Four principal Risk Categories are defined as follows: (1) Gains, (2) Losses, (3) Stuck, and (4) Mechanical; since these four Risk Categories are the most common and costly groups of troublesome events in drilling worldwide.

[0074] The Total Risk for a scenario is calculated based on the cumulative results of all of the group/category risks along both the risk and depth axes.

[0075] Risk indexing - Each individual risk parameter is used to produce an individual risk index which is a relative indicator of the likelihood that a particular risk will occur.

This is purely qualitative, but allows for comparison of the relative likelihood of one risk to another – this is especially indicative when looked at from a percentage change. Each Risk Category is used to produce a category risk index also indicating the likelihood of occurrence and useful for identifying the most likely types of trouble events to expect.

Finally, a single risk index is produced for the scenario that is specifically useful for comparing the relative risk of one scenario to another.

[0076] The ‘Automatic Well Planning Software System’ of the present invention is capable of delivering a comprehensive technical risk assessment, and it can do this automatically. Lacking an integrated model of the technical well design to relate design decisions to associated risks, the ‘Automatic Well Planning Software System’ can attribute the risks to specific design decisions and it can direct users to the appropriate place to modify a design choice in efforts to modify the risk profile of the well.

[0077] Referring to figure 9A, a Computer System 18 is illustrated. The Computer System 18 includes a Processor 18a connected to a system bus, a Recorder or Display

Device 18b connected to the system bus, and a Memory or Program Storage Device 18c connected to the system bus. The Recorder or Display Device 18b is adapted to display 'Risk Assessment Output Data' 18b1. The Memory or Program Storage Device 18c is adapted to store an 'Automatic Well Planning Risk Assessment Software' 18c1. The

5 'Automatic Well Planning Risk Assessment Software' 18c1 is originally stored on another 'program storage device', such as a hard disk; however, the hard disk was inserted into the Computer System 18 and the 'Automatic Well Planning Risk Assessment Software' 18c1 was loaded from the hard disk into the Memory or Program Storage Device 18c of the Computer System 18 of figure 9A. In addition, a Storage

10 Medium 20 containing a plurality of 'Input Data' 20a is adapted to be connected to the system bus of the Computer System 18, the 'Input Data' 20a being accessible to the Processor 18a of the Computer System 18 when the Storage Medium 20 is connected to the system bus of the Computer System 18. In operation, the Processor 18a of the Computer System 18 will execute the Automatic Well Planning Risk Assessment

15 Software 18c1 stored in the Memory or Program Storage Device 18c of the Computer System 18 while, simultaneously, using the 'Input Data' 20a stored in the Storage Medium 20 during that execution. When the Processor 18a completes the execution of the Automatic Well Planning Risk Assessment Software 18c1 stored in the Memory or Program Storage Device 18c (while using the 'Input Data' 20a), the Recorder or Display

20 Device 18b will record or display the 'Risk Assessment Output Data' 18b1, as shown in figure 9A. For example the 'Risk Assessment Output Data' 18b1 can be displayed on a display screen of the Computer System 18, or the 'Risk Assessment Output Data' 18b1 can be recorded on a printout which is generated by the Computer System 18. The Computer System 18 of figure 9A may be a personal computer (PC). The Memory or

25 Program Storage Device 18c is a computer readable medium or a program storage device which is readable by a machine, such as the processor 18a. The processor 18a may be, for example, a microprocessor, microcontroller, or a mainframe or workstation processor. The Memory or Program Storage Device 18c, which stores the 'Automatic Well Planning Risk Assessment Software' 18c1, may be, for example, a hard disk, ROM, CD-ROM,

DRAM, or other RAM, flash memory, magnetic storage, optical storage, registers, or other volatile and/or non-volatile memory.

[0078] Referring to figure 9B, a larger view of the Recorder or Display Device 18b of figure 9A is illustrated. In figure 9B, the 'Risk Assessment Output Data' 18b1 includes:

- (1) a plurality of Risk Categories, (2) a plurality of Subcategory Risks (each of which have been ranked as either a High Risk or a Medium Risk or a Low Risk), and (3) a plurality of Individual Risks (each of which have been ranked as either a High Risk or a Medium Risk or a Low Risk). The Recorder or Display Device 18b of figure 9B will display or record the 'Risk Assessment Output Data' 18b1 including the Risk Categories, the Subcategory Risks, and the Individual Risks.

[0079] Referring to figure 10, a detailed construction of the 'Automatic Well Planning Risk Assessment Software' 18c1 of figure 9A is illustrated. In figure 10, the 'Automatic Well Planning Risk Assessment Software' 18c1 includes a first block which stores the Input Data 20a, a second block 22 which stores a plurality of Risk Assessment Logical Expressions 22; a third block 24 which stores a plurality of Risk Assessment Algorithms 24, a fourth block 26 which stores a plurality of Risk Assessment Constants 26, and a fifth block 28 which stores a plurality of Risk Assessment Catalogs 28. The Risk Assessment Constants 26 include values which are used as input for the Risk Assessment Algorithms 24 and the Risk Assessment Logical Expressions 22. The Risk Assessment Catalogs 28 include look-up values which are used as input by the Risk Assessment Algorithms 24 and the Risk Assessment Logical Expressions 22. The 'Input Data' 20a includes values which are used as input for the Risk Assessment Algorithms 24 and the Risk Assessment Logical Expressions 22. The 'Risk Assessment Output Data' 18b1 includes values which are computed by the Risk Assessment Algorithms 24 and which result from the Risk Assessment Logical Expressions 22. In operation, referring to figures 9 and 10, the Processor 18a of the Computer System 18 of figure 9A executes the Automatic Well Planning Risk Assessment Software 18c1 by executing the Risk

Assessment Logical Expressions 22 and the Risk Assessment Algorithms 24 of the Risk Assessment Software 18c1 while, simultaneously, using the 'Input Data' 20a, the Risk Assessment Constants 26, and the values stored in the Risk Assessment Catalogs 28 as 'input data' for the Risk Assessment Logical Expressions 22 and the Risk Assessment Algorithms 24 during that execution. When that execution by the Processor 18a of the Risk Assessment Logical Expressions 22 and the Risk Assessment Algorithms 24 (while using the 'Input Data' 20a, Constants 26, and Catalogs 28) is completed, the 'Risk Assessment Output Data' 18b1 will be generated as a 'result'. That 'Risk Assessment Output Data' 18b1 is recorded or displayed on the Recorder or Display Device 18b of the Computer System 18 of figure 9A. In addition, that 'Risk Assessment Output Data' 18b1 can be manually input, by an operator, to the Risk Assessment Logical Expressions block 22 and the Risk Assessment Algorithms block 24 via a 'Manual Input' block 30 shown in figure 10.

15 Input Data 20a

[0080] The following paragraphs will set forth the 'Input Data' 20a which is used by the 'Risk Assessment Logical Expressions' 22 and the 'Risk Assessment Algorithms' 24.

Values of the Input Data 20a that are used as input for the Risk Assessment Algorithms

20 24 and the Risk Assessment Logical Expressions 22 are as follows:

- (1) Casing Point Depth
- (2) Measured Depth
- (3) True Vertical Depth
- 25 (4) Mud Weight
- (5) Measured Depth
- (6) ROP
- (7) Pore Pressure
- (8) Static Temperature
- 30 (9) Pump Rate
- (10) Dog Leg Severity
- (11) ECD
- (12) Inclination
- (13) Hole Size
- 35 (14) Casing Size

	(15) Easting-westing
	(16) Northing-Southing
	(17) Water Depth
5	(18) Maximum Water Depth
	(19) Maximum well Depth
	(20) Kick Tolerance
	(21) Drill Collar 1 Weight
	(22) Drill Collar 2Weight
10	(23) Drill Pipe Weight
	(24) Heavy Weight Weight
	(25) Drill Pipe Tensile Rating
	(26) Upper Wellbore Stability Limit
	(27) Lower Wellbore Stability Limit
15	(28) Unconfined Compressive Strength
	(29) Bit Size
	(30) Mechanical drilling energy (UCS integrated over distance drilled by the bit)
	(31) Ratio of footage drilled compared to statistical footage
	(32) Cumulative UCS
	(33) Cumulative Excess UCS
20	(34) Cumulative UCS Ratio
	(35) Average UCS of rock in section
	(36) Bit Average UCS of rock in section
	(37) Statistical Bit Hours
	(38) Statistical Drilled Footage for the bit
25	(39) RPM
	(40) On Bottom Hours
	(41) Calculated Total Bit Revolutions
	(42) Time to Trip
	(43) Critical Flow Rate
30	(44) Maximum Flow Rate in hole section
	(45) Minimum Flow Rate in hole section
	(46) Flow Rate
	(47) Total Nozzle Flow Area of bit
	(48) Top Of Cement
35	(49) Top of Tail slurry
	(50) Length of Lead slurry
	(51) Length of Tail slurry
	(52) Cement Density Of Lead
	(53) Cement Density Of Tail slurry
40	(54) Casing Weight per foot
	(55) Casing Burst Pressure
	(56) Casing Collapse Pressure
	(57) Casing Type Name
	(58) Hydrostatic Pressure of Cement column
45	(59) Start Depth

- (60) End Depth
- (61) Conductor
- (62) Hole Section Begin Depth
- (63) Openhole Or Cased hole completion
- 5 (64) Casing Internal Diameter
- (65) Casing Outer Diameter
- (66) Mud Type
- (67) Pore Pressure without Safety Margin
- (68) Tubular Burst Design Factor
- 10 (69) Casing Collapse Pressure Design Factor
- (70) Tubular Tension Design Factor
- (71) Derrick Load Rating
- (72) Drawworks Rating
- (73) Motion Compensator Rating
- 15 (74) Tubular Tension rating
- (75) Statistical Bit ROP
- (76) Statistical Bit RPM
- (77) Well Type
- (78) Maximum Pressure
- 20 (79) Maximum Liner Pressure Rating
- (80) Circulating Pressure
- (81) Maximum UCS of bit
- (82) Air Gap
- (83) Casing Point Depth
- 25 (84) Presence of H2S
- (85) Presence of CO2
- (86) Offshore Well
- (87) Flow Rate Maximum Limit

30 Risk Assessment Constants 26

[0081] The following paragraphs will set forth the ‘Risk Assessment Constants’ 26 which are used by the ‘Risk Assessment Logical Expressions’ 22 and the ‘Risk Assessment Algorithms’ 24. Values of the Constants 26 that are used as input data for

35 Risk Assessment Algorithms 24 and the Risk Assessment Logical Expressions 22 are as follows:

- (1) Maximum Mud Weight Overbalance to Pore Pressure
- (2) Minimum Required Collapse Design Factor
- 40 (3) Minimum Required Tension Design Factor
- (4) Minimum Required Burst Design Factor

- (5) Rock density
- (6) Seawater density

Risk Assessment Catalogs 28

5

[0082] The following paragraphs will set forth the 'Risk Assessment Catalogs' 28 which are used by the 'Risk Assessment Logical Expressions' 22 and the 'Risk Assessment Algorithms' 24. Values of the Catalogs 28 that are used as input data for Risk Assessment Algorithms 24 and the Risk Assessment Logical Expressions 22 include the following:

10

- (1) Risk Matrix Catalog
- (2) Risk Calculation Catalog
- (3) Drillstring component catalog
- (4) Drill Bit Catalog
- (5) Clearance Factor Catalog
- (6) Drill Collar Catalog
- (7) Drill Pipes Catalog
- (8) Minimum and maximum flow rate catalog
- (9) Pump catalog
- (10) Rig Catalog
- (11) Constants and variables Settings catalog
- (12) Tubular Catalog

15

20

Risk Assessment Output Data 18b1

25

[0083] The following paragraphs will set forth the 'Risk Assessment Output Data' 18b1 which are generated by the 'Risk Assessment Algorithms' 24. The 'Risk Assessment Output Data' 18b1, which is generated by the 'Risk Assessment Algorithms' 24, includes the following types of output data: (1) Risk Categories, (2) Subcategory Risks, and (3) Individual Risks. The 'Risk Categories', 'Subcategory Risks', and 'Individual Risks' included within the 'Risk Assessment Output Data' 18b1 comprise the following:

30

The following 'Risk Categories' are calculated:

35

	(1) Individual Risk
	(2) Average Individual Risk
	(3) Subcategory Risk
	(4) Average Subcategory Risk
5	(5) Total risk
	(6) Average total risk
	(7) Potential risk for each design task
	(8) Actual risk for each design task
10	The following 'Subcategory Risks' are calculated
	(1) Gains risks
	(2) Losses risks
	(3) Stuck Pipe risks
15	(4) Mechanical risks
	The following 'Individual Risks' are calculated
20	(1) H2S and CO2,
	(2) Hydrates,
	(3) Well water depth,
	(4) Tortuosity,
	(5) Dogleg severity,
	(6) Directional Drilling Index,
25	(7) Inclination,
	(8) Horizontal displacement,
	(9) Casing Wear,
	(10) High pore pressure,
	(11) Low pore pressure,
30	(12) Hard rock,
	(13) Soft Rock,
	(14) High temperature,
	(15) Water-depth to rig rating,
	(16) Well depth to rig rating,
35	(17) mud weight to kick,
	(18) mud weight to losses,
	(19) mud weight to fracture,
	(20) mud weight window,
	(21) Wellbore stability window,
40	(22) wellbore stability,
	(23) Hole section length,
	(24) Casing design factor,
	(25) Hole to casing clearance,
	(26) casing to casing clearance,
45	(27) casing to bit clearance,

- 5 (28) casing linear weight,
- (29) Casing maximum overpull,
- (30) Low top of cement,
- (31) Cement to kick,
- (32) cement to losses,
- (33) cement to fracture,
- (34) Bit excess work,
- (35) Bit work,
- 10 (36) Bit footage,
- (37) bit hours,
- (38) Bit revolutions,
- (39) Bit ROP,
- (40) Drillstring maximum overpull,
- (41) Bit compressive strength,
- 15 (42) Kick tolerance,
- (43) Critical flow rate,
- (44) Maximum flow rate,
- (45) Small nozzle area,
- (46) Standpipe pressure,
- 20 (47) ECD to fracture,
- (48) ECD to losses,
- (49) Subsea BOP,
- (50) Large Hole,
- (51) Small Hole,
- 25 (52) Number of casing strings,
- (53) Drillstring parting,
- (54) Cuttings.

Risk Assessment Logical Expressions 22

30

[0084] The following paragraphs will set forth the ‘Risk Assessment Logical Expressions’ 22. The ‘Risk Assessment Logical Expressions’ 22 will: (1) receive the ‘Input Data 20a’ including a ‘plurality of Input Data calculation results’ that has been generated by the ‘Input Data 20a’; (2) determine whether each of the ‘plurality of Input

35 Data calculation results’ represent a high risk, a medium risk, or a low risk; and (3) generate a ‘plurality of Risk Values’ (also known as a ‘plurality of Individual Risks), in response thereto, each of the plurality of Risk Values/plurality of Individual Risks representing a ‘an Input Data calculation result’ that has been ‘ranked’ as either a ‘high risk’, a ‘medium risk’, or a ‘low risk’.

The Risk Assessment Logical Expressions 22 include the following:

- Task: Scenario
- 5 Description: H2S and CO2 present for scenario indicated by user (per well)
Short Name: H2S_CO2
Data Name: H2S
Calculation: H2S and CO2 check boxes checked yes
Calculation Name: CalculateH2S_CO2
- 10 High: Both selected
Medium: Either one selected
Low: Neither selected
Unit: unitless
- 15 Task: Scenario
Description: Hydrate development (per well)
Short Name: Hydrates
Data Name: Water Depth
Calculation: = Water Depth
- 20 Calculation Name: CalculateHydrates
High: ≥ 3000
Medium: ≥ 2000
Low: < 2000
Unit: ft
- 25 Task: Scenario
Description: Hydrate development (per well)
Short Name: Well_WD
Data Name: Water Depth
- 30 Calculation: = WaterDepth
Calculation Name: CalculateHydrates
High: ≥ 5000
Medium: ≥ 1000
Low: < 1000
- 35 Unit: ft
- Task: Trajectory
Description: Dogleg severity (per depth)
Short Name: DLS
- 40 Data Name: Dog Leg Severity
Calculation: NA
Calculation Name: CalculateRisk
High: ≥ 6
Medium: ≥ 4

Low: < 4
Unit: deg/100ft

- Task: Trajectory
- 5 Description: Tortuosity (per depth)
Short Name: TORT
Data Name: Dog Leg Severity
Calculation: Summation of DLS
Calculation Name: CalculateTort
- 10 High: ≥ 90
Medium: ≥ 60
Low: < 60
Unit: deg
- 15 Task: Trajectory
Description: Inclination (per depth)
Short Name: INC
Data Name: Inclination
Calculation: NA
- 20 Calculation Name: CalculateRisk
High: ≥ 65
Medium: ≥ 40
Low: < 40
Unit: deg
- 25 Task: Trajectory
Description: Well inclinations with difficult cuttings transport conditions (per depth)
Short Name: Cutting
Data Name: Inclination
- 30 Calculation: NA
Calculation Name: CalculateCutting
High: ≥ 45
Medium: > 65
Low: < 45
- 35 Unit: deg
- Task: Trajectory
Description: Horizontal to vertical ratio (per depth)
Short Name: Hor_Displacement
- 40 Data Name: Inclination
Calculation: = Horizontal Displacement / True Vertical Depth
Calculation Name: CalculateHor Disp
High: ≥ 1.0
Medium: ≥ 0.5
- 45 Low: < 0.5

Unit: Ratio

Task: Trajectory

Description: Directional Drillability Index (per depth) Fake Threshold

5 Short Name: DDI

Data Name: Inclination

Calculation: = Calculate DDI using Resample data

Calculation Name: CalculateDDI

High: > 6.8

10 Medium: >= 6.0

Low: < 6.0

Unit: unitless

Task: EarthModel

15 Description: High or supernormal Pore Pressure (per depth)

Short Name: PP_High

Data Name: Pore Pressure without Safety Margin

Calculation: = PP

Calculation Name: CalculateRisk

20 High: >= 16

Medium: >= 12

Low: < 12

Unit: ppg

25 Task: EarthModel

Description: Depleted or subnormal Pore Pressure (per depth)

Short Name: PP_Low

Data Name: Pore Pressure without Safety Margin

Calculation: = Pore Pressure without Safety Margin

30 Calculation Name: CalculateRisk

High: <= 8.33

Medium: <= 8.65

Low: > 8.65

Unit: ppg

35

Task: EarthModel

Description: Superhard rock (per depth)

Short Name: RockHard

Data Name: Unconfined Compressive Strength

40 Calculation: = Unconfined Compressive Strength

Calculation Name: CalculateRisk

High: >= 25

Medium: >= 16

Low: < 16

45 Unit: kpsi

Task: EarthModel
 Description: Gumbo (per depth)
 Short Name: RockSoft
 5 Data Name: Unconfined Compressive Strength
 Calculation: = Unconfined Compressive Strength
 Calculation Name: CalculateRisk
 High: ≤ 2
 Medium: ≤ 4
 10 Low: > 4
 Unit: kpsi

Task: EarthModel
 Description: High Geothermal Temperature (per depth)
 15 Short Name: TempHigh
 Data Name: StaticTemperature
 Calculation: = Temp
 Calculation Name: CalculateRisk
 High: ≥ 280
 20 Medium: ≥ 220
 Low: < 220
 Unit: degF

Task: RigConstraint
 25 Description: Water depth as a ratio to the maximum water depth rating of the rig (per depth)
 Short Name: Rig_WD
 Data Name:
 Calculation: = WD , Rig WD rating
 30 Calculation Name: CalculateRig_WD
 High: ≥ 0.75
 Medium: ≥ 0.5
 Low: < 0.5
 Unit: Ratio
 35

Task: RigConstraint
 Description: Total measured depth as a ratio to the maximum depth rating of the rig (per depth)
 Short Name: Rig_MD
 40 Data Name:
 Calculation: = MD /Rig MD rating
 Calculation Name: CalculateRig_MD
 High: ≥ 0.75
 Medium: ≥ 0.5
 45 Low: < 0.5

Unit: Ratio

Task: RigConstraint

"Description: Subsea BOP or wellhead (per well), not quite sure how to compute it"

5 Short Name: SS_BOP

Data Name: Water Depth

Calculation: =

Calculation Name: CalculateHydrates

High: ≥ 3000

10 Medium: ≥ 1000

Low: < 1000

Unit: ft

Task: MudWindow

15 Description: Kick potential where Mud Weight is too low relative to Pore Pressure (per depth)

Short Name: MW_Kick

Data Name:

Calculation: = Mud Weight – Pore Pressure

20 Calculation Name: CalculateMW_Kick

High: ≤ 0.3

Medium: ≤ 0.5

Low: > 0.5

Unit: ppg

25

Task: MudWindow

Description: Loss potential where Hydrostatic Pressure is too high relative to Pore Pressure (per depth)

Short Name: MW_Loss

30 Data Name:

Calculation: = Hydrostatic Pressure – Pore Pressure

Calculation Name: CalculateMW_Loss

"PreCondition: =Mud Type (HP-WBM, ND-WBM, D-WBM)"

High: ≥ 2500

35 Medium: ≥ 2000

Low: < 2000

Unit: psi

Task: MudWindow

40 Description: Loss potential where Hydrostatic Pressure is too high relative to Pore Pressure (per depth)

Short Name: MW_Loss

Data Name:

Calculation: = Hydrostatic Pressure – Pore Pressure

45 Calculation Method: CalculateMW_Loss

"PreCondition: =Mud Type (OBM, MOBM, SOBM)"

High: ≥ 2000

Medium: ≥ 1500

Low: < 1500

5 Unit: psi

Task: MudWindow

Description: Loss potential where Mud Weight is too high relative to Fracture Gradient (per depth)

10 Short Name: MW_Frac

Data Name:

Calculation: = Upper Bound – Mud Weight

Calculation Method: CalculateMW_Frac

High: ≤ 0.2

15 Medium: ≤ 0.5

Low: > 0.5

Unit: ppg

Task: MudWindow

20 Description: Narrow mud weight window (per depth)

Short Name: MWW

Data Name:

Calculation: = Upper Wellbore Stability Limit – Pore Pressure without Safety Margin

Calculation Method: CalculateMWW

25 High: ≤ 0.5

Medium: ≤ 1.0

Low: > 1.0

Unit: ppg

30 Task: MudWindow

Description: Narrow wellbore stability window (per depth)

Short Name: WBSW

Data Name:

Calculation: = Upper Bound – Lower Bound

35 Calculation Method: CalculateWBSW

"PreCondition: =Mud Type (OBM, MOBM, SOBM)"

High: ≤ 0.3

Medium: ≤ 0.6

Low: > 0.6

40 Unit: ppg

Task: MudWindow

Description: Narrow wellbore stability window (per depth)

Short Name: WBSW

45 Data Name:

Calculation: = Upper Bound – Lower Bound
 Calculation Method: CalculateWBSW
 "PreCondition: =Mud Type (HP-WBM, ND-WBM, D-WBM)"
 High: ≤ 0.4
 5 Medium: ≤ 0.8
 Low: > 0.8
 Unit: ppg

Task: MudWindow
 10 Description: Wellbore Stability (per depth)
 Short Name: WBS
 Data Name: Pore Pressure without Safety Margin
 Calculation: = Pore Pressure without Safety Margin
 Calculation Method: CalculateWBS
 15 High: $LB \geq MW \geq PP$
 Medium: $MW \geq LB \geq PP$
 Low: $MW \geq PP \geq LB$
 Unit: unitless

20 Task: MudWindow
 Description: Hole section length (per hole section)
 Short Name: HSLength
 Data Name:
 Calculation: = HoleEnd - HoleStart
 25 Calculation Method: CalculateHSLength
 High: ≥ 8000
 Medium: ≥ 7001
 Low: < 7001
 Unit: ft

30 Task: MudWindow
 Description: Dogleg severity at Casing points for casing wear (per hole section)
 Short Name: Csg_Wear
 Data Name: Dog Leg Severity
 35 Calculation: = Hole diameter
 Calculation Method: CalculateCsg_Wear
 High: ≥ 4
 Medium: ≥ 3
 Low: < 3
 40 Unit: deg/100ft

Task: MudWindow
 Description: Number of Casing strings (per hole section)
 Short Name: Csg_Count
 45 Data Name: Casing Point Depth

Calculation: = Number of Casing strings
Calculation Method: CalculateCsg_Count
High: >= 6
Medium: >= 4
5 Low: < 4
Unit: unitless

Task: WellboreSizes
Description: Large Hole size (per hole section)
10 Short Name: Hole_Big
Data Name: Hole Size
Calculation: = Hole diameter
Calculation Method: CalculateHoleSectionRisk
High: >= 24
15 Medium: >= 18.625
Low: < 18.625
Unit: in

Task: WellboreSizes
20 Description: Small Hole size (per hole section)
Short Name: Hole_Sm
Data Name: Hole Size
Calculation: = Hole diameter
Calculation Method: CalculateHole_Sm
25 PreCondition: Onshore
High: <= 4.75
Medium: <= 6.5
Low: > 6.5
Unit: in

30 Task: WellboreSizes
Description: Small Hole size (per hole section)
Short Name: Hole_Sm
Data Name: Hole Size
35 Calculation: = Hole diameter
Calculation Method: CalculateHole_Sm
PreCondition: Offshore
High: <= 6.5
Medium: <= 7.875
40 Low: > 7.875
Unit: in

Task: TubularDesign
"Description: Casing Design Factors for Burst, Collapse, & Tension (per hole section),
45 DFb,c,t <= 1.0 for High, DFb,c,t <= 1.1 for Medium, DFb,c,t > 1.1 for Low"

Short Name: Csg_DF
 Data Name:
 Calculation: = DF/Design Factor
 Calculation Method: CalculateCsg_DF
 5 High: ≤ 1.0
 Medium: ≤ 1.1
 Low: > 1.1
 Unit: unitless

10 Task: TubularDesign
 Description: Casing string weight relative to rig lifting capabilities (per casing string)
 Short Name: Csg_Wt
 Data Name:
 Calculation: = CasingWeight/RigMinRating
 15 Calculation Method: CalculateCsg_Wt
 High: ≥ 0.95
 Medium: < 0.95
 Low: < 0.8
 Unit: Ratio

20 Task: TubularDesign
 Description: Casing string allowable Margin of Overpull (per casing string)
 Short Name: Csg_MOP
 Data Name:
 25 Calculation: = Tubular Tension rating-CasingWeight
 Calculation Method: CalculateCsg_MOP
 High: ≤ 50
 Medium: ≤ 100
 Low: > 100
 30 Unit: klbs

Task: WellboreSizes
 Description: Clearance between hole size and casing max OD (per hole section)
 Short Name: Hole_Csg
 35 Data Name:
 Calculation: = Area of hole size , Area of casing size (max OD)
 Calculation Method: CalculateHole_Csg
 High: ≤ 1.1
 Medium: ≤ 1.25
 40 Low: > 1.25
 Unit: Ratio

Task: WellboreSizes
 Description:
 45 Short Name: Csg_Csg

Data Name:
 Calculation: $= \text{CainsgID} / \text{NextMaxCasingSize}$
 Calculation Method: CalculateCsg_Csg
 High: ≤ 1.05
 5 Medium: ≤ 1.1
 Low: > 1.1
 Unit: Ratio

Task: WellboreSizes
 10 Description: Clearance between casing inside diameter and subsequent bit size (per bit run)
 Short Name: Csg_Bit
 Data Name:
 Calculation: $= \text{CainsgID} / \text{NextBit Size}$
 15 Calculation Method: CalculateCsg_Bit
 High: ≤ 1.05
 Medium: ≤ 1.1
 Low: > 1.1
 Unit: Ratio

20 Task: CementDesign
 Description: Cement height relative to design guidelines for each string type (per hole section)
 Short Name: TOC_Low
 25 Data Name:
 Calculation: $= \text{CasingBottomDepth} - \text{TopDepthOfCement}$
 Calculation Method: CalculateTOC_Low
 High: ≤ 0.75
 Medium: ≤ 1.0
 30 Low: > 1.0
 Unit: Ratio

Task: CementDesign
 Description: Kick potential where Hydrostatic Pressure is too low relative to Pore
 35 Pressure (per depth)
 Short Name: Cmt_Kick
 Data Name:
 Calculation: $= (\text{Cementing Hydrostatic Pressure} - \text{Pore Pressure}) / \text{TVD}$
 Calculation Method: CalculateCmt_Kick
 40 High: ≤ 0.3
 Medium: ≤ 0.5
 Low: > 0.5
 Unit: ppg

45 Task: CementDesign

Description: Loss potential where Hydrostatic Pressure is too high relative to Pore Pressure (per depth)

Short Name: Cmt_Loss

Data Name:

5 Calculation: = Cementing Hydrostatic Pressure – Pore Pressure

Calculation Method: CalculateCmt_Loss

High: ≥ 2500

Medium: ≥ 2000

Low: < 2000

10 Unit: psi

Task: CementDesign

Description: Loss potential where Hydrostatic Pressure is too high relative to Fracture Gradient (per depth)

15 Short Name: Cmt_Frac

Data Name:

Calculation: = (UpperBound - Cementing Hydrostatic Pressure)/TVD

Calculation Method: CalculateCmt_Frac

High: ≤ 0.2

20 Medium: ≤ 0.5

Low: > 0.5

Unit: ppg

Task: BitsSelection

25 Description: Excess bit work as a ratio to the Cumulative Mechanical drilling energy (UCS integrated over distance drilled by the bit)

Short Name: Bit_WkXS

Data Name: CumExcessCumulative UCSRatio

Calculation: = CumExcess/Cumulative UCS

30 Calculation Method: CalculateBitSectionRisk

High: ≥ 0.2

Medium: ≥ 0.1

Low: < 0.1

Unit: Ratio

35

Task: BitsSelection

Description: Cumulative bit work as a ratio to the bit catalog average Mechanical drilling energy (UCS integrated over distance drilled by the bit)

Short Name: Bit_Wk

40 Data Name:

Calculation: = Cumulative UCS/ Mechanical drilling energy (UCS integrated over distance drilled by the bit)

Calculation Method: CalculateBit_Wk

High: ≥ 1.5

45 Medium: ≥ 1.25

Low: < 1.25

Unit: Ratio

Task: BitsSelection

5 Description: Cumulative bit footage as a ratio to the bit catalog average footage (drilled length) (per depth)

Short Name: Bit_Ftg

Data Name: Ratio of footage drilled compared to statistical footage

Calculation: = Ratio of footage drilled compared to statistical footage

10 Calculation Method: CalculateBitSectionRisk

High: >= 2

Medium: >= 1.5

Low: < 1.5

Unit: Ratio

15

Task: BitsSelection

Description: Cumulative bit hours as a ratio to the bit catalog average hours (on bottom rotating time) (per depth)

Short Name: Bit_Hrs

20 Data Name: Bit_Ftg

Calculation: = On Bottom Hours/Statistical Bit Hours

Calculation Method: CalculateBit_Hrs

High: >= 2

Medium: >= 1.5

25 Low: < 1.5

Unit: Ratio

Task: BitsSelection

30 Description: Cumulative bit Krevs as a ratio to the bit catalog average Krevs (RPM*hours) (per depth)

Short Name: Bit_Krev

Data Name:

Calculation: = Cumulative Krevs , Bit average Krevs

Calculation Method: CalculateBit_Krev

35 High: >= 2

Medium: >= 1.5

Low: < 1.5

Unit: Ratio

40 Task: BitsSelection

Description: Bit ROP as a ratio to the bit catalog average ROP (per bit run)

Short Name: Bit_ROP

Data Name:

Calculation: = ROP/Statistical Bit ROP

45 Calculation Method: CalculateBit_ROP

High: ≥ 1.5
Medium: ≥ 1.25
Low: < 1.25
Unit: Ratio

5

Task: BitsSelection
Description: UCS relative to Bit UCS and Max Bit UCS (per depth)
Short Name: Bit_UCS
Data Name:

10 Calculation: = UCS
Calculation Method: CalculateBit_UCS
High: $UCS \geq \text{Max Bit UCS} \geq \text{Bit UCS}$
Medium: $\text{Max Bit UCS} \geq UCS \geq \text{Bit UCS}$
Low: $\text{Max Bit UCS} \geq \text{Bit UCS} \geq UCS$
15 Unit: Ratio

Task: DrillstringDesign
Description: Drillstring allowable Margin of Overpull (per bit run)
Short Name: DS_MOP

20 Data Name:
Calculation: = MOP
Calculation Method: CalculateDS_MOP
High: ≤ 50
Medium: ≤ 100
25 Low: > 100
Unit: klbs

Task: DrillstringDesign
"Description: Potential parting of the drillstrings where required tension approaches
30 mechanical tension limits of drill pipe, heavy weight, drill pipe, drill collars, or
connections (per bit run) "

Short Name: DS_Part
Data Name:
Calculation: = Required Tension (including MOP)/Tension limit of drilling component
35 (DP)
Calculation Method: CalculateDS_Part
High: ≥ 0.9
Medium: ≥ 0.8
Low: > 0.8
40 Unit: ratio

Task: DrillstringDesign
Description: Kick Tolerance (per hole section)
Short Name: Kick_Tol
45 Data Name: Bit_UCS

"Calculation: NA (already calculated), Exploration/Development"
Calculation Method: CalculateKick_Tol
PreCondition: Exporation
High: <= 50
5 Medium: <= 100
Low: > 100
Unit: bbl

Task: DrillstringDesign
10 Description: Kick Tolerance (per hole section)
Short Name: Kick_Tol
Data Name: Bit_UCS
"Calculation: NA (already calculated), Exploration/Development"
Calculation Method: CalculateKick_Tol
15 PreCondition: Development
High: <= 25
Medium: <= 50
Low: > 50
Unit: bbl

20 Task: Hydraulics
Description: Flow rate for hole cleaning (per depth)
Short Name: Q_Crit
"Data Name: Flow Rate, Critical Flow Rate"
25 Calculation: = Flow Rate/Critical Flow Rate
Calculation Method: CalculateQ_Crit
High: <= 1.0
Medium: <= 1.1
Low: > 1.1
30 Unit: Ratio

Task: Hydraulics
Description: Flow rate relative to pump capabilities(per depth)
Short Name: Q_Max
35 Data Name: Bit_UCS
Calculation: = Q/Qmax
Calculation Method: CalculateQ_Max
High: >= 1.0
Medium: >= 0.9
40 Low: < 0.9
Unit: Ratio

Task: Hydraulics
"Description: TFA size relative to minimum TFA (per bit run), 0.2301 = 3 of 10/32 inch,
45 0.3313 = 3 of 12/32inch"

Short Name: TFA_Low
 Data Name: Bit_UCS
 Calculation: TFA
 Calculation Method: CalculateTFA_Low
 5 High: ≤ 0.2301
 Medium: ≤ 0.3313
 Low: > 0.3313
 Unit: inch

10 Task: Hydraulics
 Description: Circulating pressure relative to rig and pump maximum pressure (per depth)
 Short Name: P_Max
 Data Name: Bit_UCS
 Calculation: P_Max
 15 Calculation Method: CalculateP_Max
 High: ≥ 1.0
 Medium: ≥ 0.9
 Low: < 0.9
 Unit: Ratio

20 Task: Hydraulics
 Description: Loss potential where ECD is too high relative to Fracture Gradient (per depth)
 Short Name: ECD_Frac
 25 Data Name: Bit_UCS
 Calculation: UpperBound-ECD
 Calculation Method: CalculateECD_Frac
 High: ≤ 0.0
 Medium: ≤ 0.2
 30 Low: > 0.2
 Unit: ppg

Task: Hydraulics
 Description: Loss potential where ECD is too high relative to Pore Pressure (per depth)
 35 Short Name: ECD_Loss
 Data Name: Bit_UCS
 Calculation: $= \text{ECD} - \text{Pore Pressure}$
 Calculation Method: CalculateECD_Loss
 "PreCondition: Mud Type (HP-WBM, ND-WBM, D-WBM)"
 40 High: ≥ 2500
 Medium: ≥ 2000
 Low: < 2000
 Unit: psi

45 Task: Hydraulics

Description: Loss potential where ECD is too high relative to Pore Pressure (per depth)

Short Name: ECD_Loss

Data Name: Bit_UCS

Calculation: = ECD – Pore Pressure

5 Calculation Method: CalculateECD_Loss

"PreCondition: Mud Type (OBM, MOBM, SOBM)"

High: ≥ 2000

Medium: ≥ 1500

Low: < 1500

10 Unit: psi

Risk Assessment Algorithms 24

[0085] Recall that the ‘Risk Assessment Logical Expressions’ 22 will: (1) receive the
15 ‘Input Data 20a’ including a ‘plurality of Input Data calculation results’ that has been
generated by the ‘Input Data 20a’; (2) determine whether each of the ‘plurality of Input
Data calculation results’ represent a high risk, a medium risk, or a low risk; and (3)
generate a plurality of Risk Values/plurality of Individual Risks in response thereto,
where each of the plurality of Risk Values/plurality of Individual Risks represents a ‘an
20 Input Data calculation result’ that has been ‘ranked’ as either a ‘high risk’, a ‘medium
risk’, or a ‘low risk’. For example, recall the following task:

Task: Hydraulics

Description: Loss potential where ECD is too high relative to Pore Pressure (per depth)

25 Short Name: ECD_Loss

Data Name: Bit_UCS

Calculation: = ECD – Pore Pressure

Calculation Method: CalculateECD_Loss

"PreCondition: Mud Type (OBM, MOBM, SOBM)"

30 High: ≥ 2000

Medium: ≥ 1500

Low: < 1500

Unit: psi

35 [0086] When the Calculation ‘ECD- Pore Pressure’ associated with the above
referenced Hydraulics task is ≥ 2000 , a ‘high’ rank is assigned to that calculation; but if
the Calculation ‘ECD - Pore Pressure’ is ≥ 1500 , a ‘medium’ rank is assigned to that

calculation, but if the Calculation 'ECD – Pore Pressure' is < 1500, a 'low' rank is assigned to that calculation.

[0087] Therefore, the 'Risk Assessment Logical Expressions' 22 will rank each of the
5 'Input Data calculation results' as either a 'high risk' or a 'medium risk' or a 'low risk'
thereby generating a 'plurality of ranked Risk Values', also known as a 'plurality of
ranked Individual Risks'. In response to the 'plurality of ranked Individual Risks'
received from the Logical Expressions 22, the 'Risk Assessment Logical Algorithms' 24
will then assign a 'value' and a 'color' to each of the plurality of ranked Individual Risks
10 received from the Logical Expressions 22, where the 'value' and the 'color' depends upon
the particular ranking (i.e., the 'high risk' rank, or the 'medium risk' rank, or the 'low
risk' rank) that is associated with each of the plurality of ranked Individual Risks. The
'value' and the 'color' is assigned, by the 'Risk Assessment Algorithms' 24, to each of
the plurality of Individual Risks received from the Logical Expressions 22 in the
15 following manner:

Risk Calculation #1 - Individual Risk Calculation:

[0088] Referring to the 'Risk Assessment Output Data' 18b1 set forth above, there are
20 fifty-four (54) 'Individual Risks' currently specified. For an 'Individual Risk':

a High risk = 90,
a Medium risk = 70, and
a Low risk = 10

25 High risk color code = Red
Medium risk color code = Yellow
Low risk color code = Green

30 [0089] If the 'Risk Assessment Logical Expressions' 22 assigns a 'high risk' rank to a
particular 'Input Data calculation result', the 'Risk Assessment Algorithms' 24 will then
assign a value '90' to that 'Input Data calculation result' and a color 'red' to that 'Input
Data calculation result'.

[0090] If the 'Risk Assessment Logical Expressions' 22 assigns a 'medium risk' rank to a particular 'Input Data calculation result', the 'Risk Assessment Algorithms' 24 will then assign a value '70' to that 'Input Data calculation result' and a color 'yellow' to that
5 'Input Data calculation result'.

[0091] If the 'Risk Assessment Logical Expressions' 22 assigns a 'low risk' rank to a particular 'Input Data calculation result', the 'Risk Assessment Algorithms' 24 will then assign a value '10' to that 'Input Data calculation result' and a color 'green' to that 'Input
10 Data calculation result'.

[0092] Therefore, in response to the 'Ranked Individual Risks' from the Logical Expressions 22, the Risk Assessment Algorithms 24 will assign to each of the 'Ranked Individual Risks' a value of 90 and a color 'red' for a high risk, a value of 70 and a color
15 'yellow' for the medium risk, and a value of 10 and a color 'green' for the low risk. However, in addition, in response to the 'Ranked Individual Risks' from the Logical Expressions 22, the Risk Assessment Algorithms 24 will also generate a plurality of ranked 'Risk Categories' and a plurality of ranked 'Subcategory Risks'

20 [0093] Referring to the 'Risk Assessment Output Data' 18b1 set forth above, the 'Risk Assessment Output Data' 18b1 includes: (1) eight 'Risk Categories', (2) four 'Subcategory Risks', and (3) fifty-four (54) 'Individual Risks' [that is, 54 individual risks plus 2 'gains' plus 2 'losses' plus 2 'stuck' plus 2 'mechanical' plus 1 'total' = 63 risks].

25 [0094] The eight 'Risk Categories' include the following: (1) an Individual Risk, (2) an Average Individual Risk, (3) a Risk Subcategory (or Subcategory Risk), (4) an Average Subcategory Risk, (5) a Risk Total (or Total Risk), (6) an Average Total Risk, (7) a potential Risk for each design task, and (8) an Actual Risk for each design task.

[0095] Recalling that the 'Risk Assessment Algorithms' 24 have already established and generated the above referenced 'Risk Category (1)' [i.e., the plurality of ranked Individual Risks'] by assigning a value of 90 and a color 'red' to a high risk 'Input Data calculation result', a value of 70 and a color 'yellow' to a medium risk 'Input Data calculation result', and a value of 10 and a color 'green' to a low risk 'Input Data calculation result', the 'Risk Assessment Algorithms' 24 will now calculate and establish and generate the above referenced 'Risk Categories (2) through (8)' in response to the plurality of Risk Values/plurality of Individual Risks received from the 'Risk Assessment Logical Expressions' 22 in the following manner:

Risk Calculation #2 - Average Individual Risk:

The average of all of the 'Risk Values' is calculated as follows:

$$\text{Average individual risk} = \frac{\sum_i^n \text{Riskvalue}_i}{n}$$

[0096] In order to determine the 'Average Individual Risk', sum the above referenced 'Risk Values' and then divide by the number of such 'Risk Values', where i = number of sample points. The value for the 'Average Individual Risk' is displayed at the bottom of the colored individual risk track.

Risk Calculation #3 - Risk subcategory

[0097] Referring to the 'Risk Assessment Output Data' 18b1 set forth above, the following 'Subcategory Risks' are defined: (a) gains, (b) losses, (c) stuck and (d) mechanical, where a 'Subcategory Risk' (or 'Risk Subcategory') is defined as follows:

$$\text{Risk Subcategory} = \frac{\sum_j^n (\text{Riskvalue}_j \times \text{severity}_j \times N_j)}{\sum_j (\text{severity}_j \times N_j)}$$

j = number of individual risks,

$0 \leq \text{Severity} \leq 5$, and

N_j = either 1 or 0 depending on whether the Risk Value_j contributes to the sub category

5 Severity_j = from the risk matrix catalog.

Red risk display for *Risk Subcategory* ≥ 40

Yellow risk display for $20 \leq \text{Risk Subcategory} < 40$

Green risk display for *Risk Subcategory* < 20

10

Risk Calculation #4 - Average subcategory risk:

$$\text{Average subcategory risk} = \frac{\sum_i^n (\text{Risk Subcategory}_i \times \text{risk multiplier}_i)}{\sum_i^n \text{risk multiplier}_i}$$

15 n = number of sample points.

The value for the average subcategory risk is displayed at the bottom of the colored subcategory risk track.

Risk Multiplier = 3 for *Risk Subcategory* ≥ 40 ,

20 Risk Multiplier = 2 for $20 \leq \text{Risk Subcategory} < 40$

Risk Multiplier = 1 for *Risk Subcategory* < 20

Risk Calculation #5 - Total Risk

25 The total risk calculation is based on the following categories: (a) gains, (b) losses, (c) stuck, and (d) mechanical.

$$Risk\ Total = \frac{\sum_1^4 Risk\ subcategory_k}{4} \text{ where } k = \text{number of subcategories}$$

Red risk display for $Risk\ total \geq 40$

Yellow risk display for $20 \leq Risk\ Total < 40$

Green risk display for $Risk\ Total < 20$

5

Risk Calculation #6 – Average Total Risk

$$Average\ total\ risk = \frac{\sum_1^n (Risk\ Subcategory_i \times risk\ multiplier_i)}{\sum_1^n risk\ multiplier_i}$$

n = number of sample points.

10

Risk Multiplier = 3 for $Risk\ Subcategory \geq 40$,

Risk Multiplier = 2 for $20 \leq Risk\ Subcategory < 40$

Risk Multiplier = 1 for $Risk\ Subcategory < 20$

15 The value for the average total risk is displayed at the bottom of the colored total risk track.

Risk calculation #7 - Risks per design task:

20 The following 14 design tasks have been defined: Scenario, Trajectory, Mechanical Earth Model, Rig, Wellbore stability, Mud weight and casing points, Wellbore Sizes, Casing, Cement, Mud, Bit, Drillstring, Hydraulics, and Time design. There are currently 54 individual risks specified.

25 Risk calculation #7A - Potential maximum risk per design task

$$Potential Risk_k = \frac{\sum_{j=1}^{55} (90 \times Severity_{k,j} \times N_{k,j})}{\sum_{j=1}^{55} (Severity_{k,j} \times N_{k,j})}$$

k = index of design tasks, there are 14 design tasks,

N_j = either 0 or 1 depending on whether the Risk Value_j contributes to the design task.

5 $0 \leq Severity \leq 5$

Risk calculation #7B - Actual risk per design task

$$Actual Risk_k = \frac{\sum_{j=1}^{55} (Average Individual Risk_j \times Severity_j \times N_{k,j})}{\sum_{j=1}^{55} (Severity_j \times N_{k,j})}$$

10 k = index of design tasks, there are 14 design tasks

$$N_{k,j} \in [0, \dots, M]$$

$$0 \leq Severity_j \leq 5$$

The 'Severity' in the above equations are defined as follows:

15

Risk	Severity
H2S_CO2	2.67
Hydrates	3.33
Well_WD	3.67
DLS	3
TORT	3
Well_MD	4.33
INC	3
Hor_Disb	4.67
DDI	4.33
PP_High	4.33
PP_Low	2.67
RockHard	2
RockSoft	1.33
TempHigh	3
Rig_WD	5
Rig_MD	5
SS_BOP	3.67
MW_Kick	4
MW_Loss	3

MW_Frac	3.33
MWW	3.33
WBS	3
WBSW	3.33
HSLength	3
Hole_Big	2
Hole_Sm	2.67
Hole_Csg	2.67
Csg_Csg	2.33
Csg_Bit	1.67
Csg_DF	4
Csg_Wt	3
Csg_MOP	2.67
Csg_Wear	1.33
Csg_Count	4.33
TOC_Low	1.67
Cmt_Kick	3.33
Cmt_Loss	2.33
Cmt_Frac	3.33
Bit_Wk	2.33
Bit_WkXS	2.33
Bit_Ftg	2.33
Bit_Hrs	2
Bit_Krev	2
Bit_ROP	2
Bit_UCS	3
DS_MOP	3.67
DS_Part	3
Kick_Tol	4.33
Q_Crit	2.67
Q_Max	3.33
Cutting	3.33
P_Max	4
TFA_Low	1.33
ECD_Frac	4
ECD_Loss	3.33

[0098] Refer now to figure 11 which will be used during the following functional description of the operation of the present invention.

- 5 [0099] A functional description of the operation of the 'Automatic Well Planning Risk Assessment Software' 18c1 will be set forth in the following paragraphs with reference to figures 1 through 11 of the drawings.

[00100] The Input Data 20a shown in figure 9A will be introduced as 'input data' to the Computer System 18 of figure 9A. The Processor 18a will execute the Automatic Well Planning Risk Assessment Software 18c1, while using the Input Data 20a, and, responsive thereto, the Processor 18a will generate the Risk Assessment Output Data 18b1, the Risk Assessment Output Data 18b1 being recorded or displayed on the Recorder or Display Device 18b in the manner illustrated in figure 9B. The Risk Assessment Output Data 18b1 includes the 'Risk Categories', the 'Subcategory Risks', and the 'Individual Risks'. When the Automatic Well Planning Risk Assessment Software 18c1 is executed by the Processor 18a of figure 9A, referring to figures 10 and 11, the Input Data 20a (and the Risk Assessment Constants 26 and the Risk Assessment Catalogs 28) are collectively provided as 'input data' to the Risk Assessment Logical Expressions 22. Recall that the Input Data 20a includes a 'plurality of Input Data Calculation results'. As a result, as denoted by element numeral 32 in figure 11, the 'plurality of Input Data Calculation results' associated with the Input Data 20a will be provided directly to the Logical Expressions block 22 in figure 11. During that execution of the Logical Expressions 22 by the Processor 18a, each of the 'plurality of Input Data Calculation results' from the Input Data 20a will be compared with each of the 'logical expressions' in the Risk Assessment Logical Expressions block 22 in figure 11. When a match is found between an 'Input Data Calculation result' from the Input Data 20a and an 'expression' in the Logical Expressions block 22, a 'Risk Value' or 'Individual Risk' 34 will be generated (by the Processor 18a) from the Logical Expressions block 22 in figure 11. As a result, since a 'plurality of Input Data Calculation results' 32 from the Input Data 20a have been compared with a 'plurality of expressions' in the Logical Expressions' block 22 in figure 11, the Logical Expressions block 22 will generate a plurality of Risk Values/plurality of Individual Risks 34 in figure 11, where each of the plurality of Risk Values/plurality of Individual Risks on line 34 in figure 11 that are generated by the Logical Expressions block 22 will represent an 'Input Data Calculation result' from the Input Data 20a that has been ranked as either a 'High Risk', or a 'Medium Risk', or a 'Low Risk' by the Logical Expressions block 22. Therefore, a 'Risk Value' or 'Individual Risk' is defined as an 'Input Data Calculation

result' from the Input Data 20a that has been matched with one of the 'expressions' in the Logical Expressions 22 and ranked, by the Logical Expressions block 22, as either a 'High Risk', or a 'Medium Risk', or a 'Low Risk'. For example, consider the following 'expression' in the Logical Expressions' 22:

5

Task: MudWindow

Description: Hole section length (per hole section)

Short Name: HSLength

Data Name:

10 Calculation: = HoleEnd - HoleStart

Calculation Method: CalculateHSLength

High: >= 8000

Medium: >= 7001

Low: < 7001

15

[00101] The 'Hole End – HoleStart' calculation is an 'Input Data Calculation result' from the Input Data 20a. The Processor 18a will find a match between the 'Hole End – HoleStart Input Data Calculation result' originating from the Input Data 20a and the above identified 'expression' in the Logical Expressions 22. As a result, the Logical
20 Expressions block 22 will 'rank' the 'Hole End – HoleStart Input Data Calculation result' as either a 'High Risk', or a 'Medium Risk', or a 'Low Risk' depending upon the value of the 'Hole End – HoleStart Input Data Calculation result'.

[00102] When the 'Risk Assessment Logical Expressions' 22 ranks the 'Input Data
25 calculation result' as either a 'high risk' or a 'medium risk' or a 'low risk' thereby generating a plurality of ranked Risk Values/plurality of ranked Individual Risks, the 'Risk Assessment Logical Algorithms' 24 will then assign a 'value' and a 'color' to that ranked 'Risk Value' or ranked 'Individual Risk', where the 'value' and the 'color' depends upon the particular ranking (i.e., the 'high risk' rank, or the 'medium risk' rank,
30 or the 'low risk' rank) that is associated with that 'Risk Value' or 'Individual Risk'. The 'value' and the 'color' is assigned, by the 'Risk Assessment Logical Algorithms' 24, to the ranked 'Risk Values' or ranked 'Individual Risks' in the following manner:

a High risk = 90,

a Medium risk = 70, and
a Low risk = 10

High risk color code = Red

5 Medium risk color code = Yellow

Low risk color code = Green

[00103] If the 'Risk Assessment Logical Expressions' 22 assigns a 'high risk' rank to the
'Input Data calculation result' thereby generating a ranked 'Individual Risk', the 'Risk
10 Assessment Logical Algorithms' 24 assigns a value '90' to that ranked 'Risk Value' or
ranked 'Individual Risk' and a color 'red' to that ranked 'Risk Value' or that ranked
'Individual Risk'. If the 'Risk Assessment Logical Expressions' 22 assigns a 'medium
risk' rank to the 'Input Data calculation result' thereby generating a ranked 'Individual
Risk', the 'Risk Assessment Logical Algorithms' 24 assigns a value '70' to that ranked
15 'Risk Value' or ranked 'Individual Risk' and a color 'yellow' to that ranked 'Risk Value'
or that ranked 'Individual Risk'. If the 'Risk Assessment Logical Expressions' 22
assigns a 'low risk' rank to the 'Input Data calculation result' thereby generating a ranked
'Individual Risk', the 'Risk Assessment Logical Algorithms' 24 assigns a value '10' to
that ranked 'Risk Value' or ranked 'Individual Risk' and a color 'green' to that ranked
20 'Risk Value' or that ranked 'Individual Risk'.

[00104] Therefore, in figure 11, a plurality of ranked Individual Risks (or ranked Risk
Values) is generated, along line 34, by the Logical Expressions block 22, the plurality of
ranked Individual Risks (which forms a part of the 'Risk Assessment Output Data' 18b1)
25 being provided directly to the 'Risk Assessment Algorithms' block 24. The 'Risk
Assessment Algorithms' block 24 will receive the plurality of ranked Individual Risks'
from line 34 and, responsive thereto, the 'Risk Assessment Algorithms' 24 will: (1)
generate the 'Ranked Individual Risks' including the 'values' and 'colors' associated
therewith in the manner described above, and, in addition, (2) calculate and generate the
30 'Ranked Risk Categories' 40 and the 'Ranked Subcategory Risks' 40 associated with the
'Risk Assessment Output Data' 18b1. The 'Ranked Risk Categories' 40 and the 'Ranked
Subcategory Risks' 40 and the 'Ranked Individual Risks' 40 can now be recorded or

displayed on the Recorder or Display device 18b. Recall that the 'Ranked Risk Categories' 40 include: an Average Individual Risk, an Average Subcategory Risk, a Risk Total (or Total Risk), an Average Total Risk, a potential Risk for each design task, and an Actual Risk for each design task. Recall that the 'Ranked Subcategory Risks' 40

5 include: a Risk Subcategory (or Subcategory Risk).

[00105] As a result, recalling that the 'Risk Assessment Output Data' 18b1 includes 'one or more Risk Categories' and 'one or more Subcategory Risks' and 'one or more Individual Risks', the 'Risk Assessment Output Data' 18b1, which includes the Risk

10 Categories 40 and the Subcategory Risks 40 and the Individual Risks 40, can now be recorded or displayed on the Recorder or Display Device 18b of the Computer System 18 shown in figure 9A.

[00106] As noted earlier, the 'Risk Assessment Algorithms' 24 will receive the 'Ranked Individual Risks' from the Logical Expressions 22 along line 34 in figure 11; and,

15 responsive thereto, the 'Risk Assessment Algorithms' 24 will (1) assign the 'values' and the 'colors' to the 'Ranked Individual Risks' in the manner described above, and, in addition, (2) calculate and generate the 'one or more Risk Categories' 40 and the 'one or more Subcategory Risks' 40 by using the following equations (set forth above).

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[00107] The average Individual Risk is calculated from the 'Risk Values' as follows:

$$\text{Average individual risk} = \frac{\sum_i^n \text{Riskvalue}_i}{n}$$

25 [00108] The Subcategory Risk, or Risk Subcategory, is calculated from the 'Risk Values' and the 'Severity', as defined above, as follows:

$$\text{Risk Subcategory} = \frac{\sum_j^n (\text{Riskvalue}_j \times \text{severity}_j \times N_j)}{\sum_j (\text{severity}_j \times N_j)}$$

[00109] The Average Subcategory Risk is calculated from the Risk Subcategory in the following manner, as follows:

$$5 \quad \text{Average subcategory risk} = \frac{\sum_i^n (\text{Risk Subcategory}_i \times \text{risk multiplier}_i)}{\sum_i^n \text{risk multiplier}_i}$$

[00110] The Risk Total is calculated from the Risk Subcategory in the following manner, as follows:

$$10 \quad \text{Risk Total} = \frac{\sum_k^4 \text{Risk subcategory}_k}{4}$$

[00111] The Average Total Risk is calculated from the Risk Subcategory in the following manner, as follows:

$$15 \quad \text{Average total risk} = \frac{\sum_i^n (\text{Risk Subcategory}_i \times \text{risk multiplier}_i)}{\sum_i^n \text{risk multiplier}_i}$$

[00112] The Potential Risk is calculated from the Severity, as defined above, as follow:

$$\text{Potential Risk}_k = \frac{\sum_{j=1}^{55} (90 \times \text{Severity}_{k,j} \times N_{k,j})}{\sum_{j=1}^{55} (\text{Severity}_{k,j} \times N_{k,j})}$$

20

[00113] The Actual Risk is calculated from the Average Individual Risk and the Severity (defined above) as follows:

$$Actual\ Risk_k = \frac{\sum_{j=1}^{55} (Average\ Individual\ Risk_j \times Severity_{,j} \times N_{k,j})}{\sum_{j=1}^{55} (Severity_j \times N_{k,j})}$$

[00114] Recall that the Logical Expressions block 22 will generate a ‘plurality of Risk Values/Ranked Individual Risks’ along line 34 in figure 11, where each of the ‘plurality of Risk Values/Ranked Individual Risks’ generated along line 34 represents a received ‘Input Data Calculation result’ from the Input Data 20a that has been ‘ranked’ as either a ‘High Risk’, or a ‘Medium Risk’, or a ‘Low Risk’ by the Logical Expressions 22. A ‘High Risk’ will be assigned a ‘Red’ color, and a ‘Medium Risk’ will be assigned a ‘Yellow’ color, and a ‘Low Risk’ will be assigned a ‘Green’ color. Therefore, noting the word ‘rank’ in the following, the Logical Expressions block 22 will generate (along line 34 in figure 11) a ‘plurality of ranked Risk Values/ranked Individual Risks’.

[00115] In addition, in figure 11, recall that the ‘Risk Assessment Algorithms’ block 24 will receive (from line 34) the ‘plurality of ranked Risk Values/ranked Individual Risks’ from the Logical Expressions block 22. In response thereto, noting the word ‘rank’ in the following, the ‘Risk Assessment Algorithms’ block 24 will generate: (1) the ‘one or more Individual Risks having ‘values’ and ‘colors’ assigned thereto, (2) the ‘one or more ranked Risk Categories’ 40, and (3) the ‘one or more ranked Subcategory Risks’ 40. Since the ‘Risk Categories’ and the ‘Subcategory Risks’ are each ‘ranked’, a ‘High Risk’ (associated with a Risk Category 40 or a Subcategory Risk 40) will be assigned a ‘Red’ color, and a ‘Medium Risk’ will be assigned a ‘Yellow’ color, and a ‘Low Risk’ will be assigned a ‘Green’ color. In view of the above ‘rankings’ and the colors associated therewith, the ‘Risk Assessment Output Data’ 18b1, including the ‘ranked’ Risk Categories 40 and the ‘ranked’ Subcategory Risks 40 and the ‘ranked’ Individual Risks 38, will be recorded or displayed on the Recorder or Display Device 18b of the Computer System 18 shown in figure 9A in the manner illustrated in figure 9B.

Automatic Well Planning Software System – Bit Selection sub-task 14a

[00116] In figure 8, the Bit Selection sub-task 14a is illustrated.

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[00117] The selection of Drill bits is a manual subjective process based heavily on personal, previous experiences. The experience of the individual recommending or selecting the drill bits can have a large impact on the drilling performance for the better or for the worse. The fact that bit selection is done primarily based on personal experiences and uses little information of the actual rock to be drilled makes it very easy to choose the incorrect bit for the application.

10

[00118] The Bit Selection sub-task 14a utilizes an ‘Automatic Well Planning Bit Selection software’ to automatically generate the required drill bits to drill the specified hole sizes through the specified hole section at unspecified intervals of earth. The ‘Automatic Well Planning Bit Selection software’ includes a piece of software (called an ‘algorithm’) that is adapted for automatically selecting the required sequence of drill bits to drill each hole section (defined by a top/bottom depth interval and diameter) in the well. It uses statistical processing of historical bit performance data and several specific Key Performance Indicators (KPI) to match the earth properties and rock strength data to the appropriate bit while optimizing the aggregate time and cost to drill each hole section. It determines the bit life and corresponding depths to pull and replace a bit based on proprietary algorithms, statistics, logic, and risk factors.

15

20

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[00119] Referring to figure 12, a Computer System 42 is illustrated. The Computer System 42 includes a Processor 42a connected to a system bus, a Recorder or Display Device 42b connected to the system bus, and a Memory or Program Storage Device 42c connected to the system bus. The Recorder or Display Device 42b is adapted to display ‘Bit Selection Output Data’ 42b1. The Memory or Program Storage Device 42c is adapted to store an ‘Automatic Well Planning Bit selection Software’ 42c1. The ‘Automatic Well Planning Bit selection Software’ 42c1 is originally stored on another

30

'program storage device', such as a hard disk; however, the hard disk was inserted into the Computer System 42 and the 'Automatic Well Planning Bit selection Software' 42c1 was loaded from the hard disk into the Memory or Program Storage Device 42c of the Computer System 42 of figure 12. In addition, a Storage Medium 44 containing a plurality of 'Input Data' 44a is adapted to be connected to the system bus of the Computer System 42, the 'Input Data' 44a being accessible to the Processor 42a of the Computer System 42 when the Storage Medium 44 is connected to the system bus of the Computer System 42. In operation, the Processor 42a of the Computer System 42 will execute the Automatic Well Planning Bit selection Software 42c1 stored in the Memory or Program Storage Device 42c of the Computer System 42 while, simultaneously, using the 'Input Data' 44a stored in the Storage Medium 44 during that execution. When the Processor 42a completes the execution of the Automatic Well Planning Bit selection Software 42c1 stored in the Memory or Program Storage Device 42c (while using the 'Input Data' 44a), the Recorder or Display Device 42b will record or display the 'Bit selection Output Data' 42b1, as shown in figure 12. For example the 'Bit selection Output Data' 42b1 can be displayed on a display screen of the Computer System 42, or the 'Bit selection Output Data' 42b1 can be recorded on a printout which is generated by the Computer System 42. The 'Input Data' 44a and the 'Bit Selection Output Data' 42b1 will be discussed and specifically identified in the following paragraphs of this specification. The 'Automatic Well Planning Bit Selection software' 42c1 will also be discussed in the following paragraphs of this specification. The Computer System 42 of figure 12 may be a personal computer (PC). The Memory or Program Storage Device 42c is a computer readable medium or a program storage device which is readable by a machine, such as the processor 42a. The processor 42a may be, for example, a microprocessor, a microcontroller, or a mainframe or workstation processor. The Memory or Program Storage Device 42c, which stores the 'Automatic Well Planning Bit selection Software' 42c1, may be, for example, a hard disk, ROM, CD-ROM, DRAM, or other RAM, flash memory, magnetic storage, optical storage, registers, or other volatile and/or non-volatile memory.

[00120] Referring to figure 13, a detailed construction of the 'Automatic Well Planning Bit selection Software' 42c1 of figure 12 is illustrated. In figure 13, the 'Automatic Well Planning Bit selection Software' 42c1 includes a first block which stores the Input Data 44a, a second block 46 which stores a plurality of Bit selection Logical Expressions 46; a
5 third block 48 which stores a plurality of Bit selection Algorithms 48, a fourth block 50 which stores a plurality of Bit selection Constants 50, and a fifth block 52 which stores a plurality of Bit selection Catalogs 52. The Bit selection Constants 50 include values which are used as input for the Bit selection Algorithms 48 and the Bit selection Logical Expressions 46. The Bit selection Catalogs 52 include look-up values which are used as
10 input by the Bit selection Algorithms 48 and the Bit selection Logical Expressions 46.

The 'Input Data' 44a includes values which are used as input for the Bit selection Algorithms 48 and the Bit selection Logical Expressions 46. The 'Bit selection Output Data' 42b1 includes values which are computed by the Bit selection Algorithms 48 and which result from the Bit selection Logical Expressions 46. In operation, referring to
15 figures 12 and 13, the Processor 42a of the Computer System 42 of figure 12 executes the Automatic Well Planning Bit selection Software 42c1 by executing the Bit selection Logical Expressions 46 and the Bit selection Algorithms 48 of the Bit selection Software 42c1 while, simultaneously, using the 'Input Data' 44a, the Bit selection Constants 50, and the values stored in the Bit selection Catalogs 52 as 'input data' for the Bit selection
20 Logical Expressions 46 and the Bit selection Algorithms 48 during that execution. When that execution by the Processor 42a of the Bit selection Logical Expressions 46 and the Bit selection Algorithms 48 (while using the 'Input Data' 44a, Constants 50, and Catalogs 52) is completed, the 'Bit selection Output Data' 42b1 will be generated as a 'result'.

The 'Bit selection Output Data' 42b1 is recorded or displayed on the Recorder or Display
25 Device 42b of the Computer System 42 of figure 12. In addition, that 'Bit selection Output Data' 42b1 can be manually input, by an operator, to the Bit selection Logical Expressions block 46 and the Bit selection Algorithms block 48 via a 'Manual Input' block 54 shown in figure 13.

Input Data 44a

[00121] The following paragraphs will set forth the 'Input Data' 44a which is used by the
5 'Bit Selection Logical Expressions' 46 and the 'Bit Selection Algorithms' 48. Values of
the Input Data 44a that are used as input for the Bit Selection Algorithms 48 and the Bit
Selection Logical Expressions 46 include the following:

- 10 (1) Measured Depth
- (2) Unconfined Compressive Strength
- (3) Casing Point Depth
- (4) Hole Size
- (5) Conductor
- (6) Casing Type Name
- 15 (7) Casing Point
- (8) Day Rate Rig
- (9) Spread Rate Rig
- (10) Hole Section Name

20 Bit selection Constants 50

[00122] The 'Bit Selection Constants' 50 are used by the 'Bit selection Logical
Expressions' 46 and the 'Bit selection Algorithms' 48. The values of the 'Bit Selection
Constants 50 that are used as input data for Bit selection Algorithms 48 and the Bit
25 selection Logical Expressions 46 include the following: Trip Speed

Bit selection Catalogs 52

[00123] The 'Bit selection Catalogs' 52 are used by the 'Bit selection Logical
30 Expressions' 46 and the 'Bit selection Algorithms' 48. The values of the Catalogs 52 that
are used as input data for Bit selection Algorithms 48 and the Bit selection Logical
Expressions 46 include the following: Bit Catalog

Bit selection Output Data 42b1

[00124] The 'Bit selection Output Data' 42b1 is generated by the 'Bit selection

5 Algorithms' 48. The 'Bit selection Output Data' 42b1, that is generated by the 'Bit selection Algorithms' 48, includes the following types of output data:

- (1) Measured Depth
- (2) Cumulative Unconfined Compressive Strength (UCS)
- 10 (3) Cumulative Excess UCS
- (4) Bit Size
- (5) Bit Type
- (6) Start Depth
- (7) End Depth
- 15 (8) Hole Section Begin Depth
- (9) Average UCS of rock in section
- (10) Maximum UCS of bit
- (11) BitAverage UCS of rock in section
- (12) Footage
- 20 (13) Statistical Drilled Footage for the bit
- (14) Ratio of footage drilled compared to statistical footage
- (15) Statistical Bit Hours
- (16) On Bottom Hours
- (17) Rate of Penetration (ROP)
- 25 (18) Statistical Bit Rate of Penetration (ROP)
- (19) Mechanical drilling energy (UCS integrated over distance drilled by the bit)
- (20) Weight On Bit
- (21) Revolutions per Minute (RPM)
- (22) Statistical Bit RPM
- 30 (23) Calculated Total Bit Revolutions
- (24) Time to Trip
- (25) Cumulative Excess as a ration to the Cumulative UCS
- (26) Bit Cost
- (27) Hole Section Name

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Bit selection Logical Expressions 46

[00125] The following paragraphs will set forth the 'Bit selection Logical Expressions'

46. The 'Bit selection Logical Expressions' 46 will: (1) receive the 'Input Data 44a',

including a 'plurality of Input Data calculation results' that has been generated by the 'Input Data 44a'; and (2) evaluate the 'Input Data calculation results' during the processing of the 'Input Data'.

5 [00126] The Bit Selection Logical Expressions 46, which evaluate the processing of the Input Data 44a, include the following:

- (1) Verify the hole size and filter out the bit sizes that do not match the hole size.
- (2) Check if the bit is not drilling beyond the casing point.
- 10 (3) Check the cumulative mechanical drilling energy for the bit run and compare it with the statistical mechanical drilling energy for that bit, and assign the proper risk to the bit run.
- (4) Check the cumulative bit revolutions and compare it with the statistical bit revolutions for that bit type and assign the proper risk to the bit run.
- 15 (5) Verify that the encountered rock strength is not outside the range of rock strengths that is optimum for the selected bit type.
- (6) Extend footage by 25% in case the casing point could be reached by the last selected bit.

20 Bit Selection Algorithms 48

[00127] The following paragraphs will set forth the 'Bit Selection Algorithms' 48. The 'Bit Selection Algorithms' 48 will receive the output from the 'Bit Selection Logical Expressions' 46 and process that 'output from the Bit Selection Logical Expressions 46' in the following manner:

- (1) Read variables and constants
- (2) Read catalogs
- (3) Build cumulative rock strength curve from casing point to casing point.

30
$$CumUCS = \int_{start}^{end} (UCS) d \text{ ft}$$

- (4) Determine the required hole size
- (5) Find the bit candidates that match the closest unconfined compressive strength of the rock to drill.
- (6) Determine the end depth of the bit by comparing the historical drilling energy with the cumulative rock strength curve for all bit candidates.
- (7) Calculate the cost per foot for each bit candidate taking into accounts the rig rate, trip speed and drilling rate of penetration.

$$TOT\ Cost = (RIG\ RATE + SPREAD\ RATE) \left(T_TripIn + \frac{footage}{ROP} + T_Trip \right) + Bit\ Cost$$

- (8) Evaluate which bit candidate is most economic.
- (9) Calculate the remaining cumulative rock strength to casing point.
- (10) Repeat step 5 to 9 until the end of the hole section
- (11) Build cumulative UCS
- (12) Select bits – display bit performance and operating parameters
- (13) Remove sub-optimum bits
- (14) Find most economic bit based on cost per foot

[00128] Refer now to figures 14A and 14B which will be used during the following functional description.

[00129] A functional description of the operation of the 'Automatic Well Planning Bit Selection Software' 42c1 will be set forth in the following paragraphs with reference to figures 1 through 14B of the drawings.

[00130] Recall that the selection of Drill bits is a manual subjective process based heavily on personal, previous experiences. The experience of the individual recommending or selecting the drill bits can have a large impact on the drilling performance for the better or for the worse. The fact that bit selection is done primarily based on personal experiences and uses little information of the actual rock to be drilled makes it very easy to choose the incorrect bit for the application. Recall that the Bit

Selection sub-task 14a utilizes an 'Automatic Well Planning Bit Selection software' 42c1 to automatically generate the required roller cone drill bits to drill the specified hole sizes through the specified hole section at unspecified intervals of earth. The 'Automatic Well Planning Bit Selection software' 42c1 includes the 'Bit Selection Logical Expressions' 46
5 and the 'Bit Selection Algorithms' 48 that are adapted for automatically selecting the required sequence of drill bits to drill each hole section (defined by a top/bottom depth interval and diameter) in the well. The 'Automatic Well Planning Bit Selection software' 42c1 uses statistical processing of historical bit performance data and several specific Key Performance Indicators (KPI) to match the earth properties and rock strength data to the
10 appropriate bit while optimizing the aggregate time and cost to drill each hole section. It determines the bit life and corresponding depths to pull and replace a bit based on proprietary algorithms, statistics, logic, and risk factors.

[00131] In figure 14A, the Input Data 44a represents a set of Earth formation
15 characteristics, where the Earth formation characteristics are comprised of data representing characteristics of a particular Earth formation 'To Be Drilled'. The Logical Expressions and Algorithms 46/48 are comprised of Historical Data 60, where the Historical Data 60 can be viewed as a table consisting of two columns: a first column 60a including 'historical Earth formation characteristics', and a second column 60b including
20 'sequences of drill bits used corresponding to the historical Earth formation characteristics'. The Recorder or Display device 42b will record or display 'Bit Selection Output Data' 42b, where the 'Bit Selection Output Data' 42b is comprised of the 'Selected Sequence of Drill Bits, and other associated data'. In operation, referring to figure 14A, the Input Data 44a represents a set of Earth formation characteristics
25 associated with an Earth formation 'To Be Drilled'. The 'Earth formation characteristics (associated with a section of Earth Formation 'to be drilled') corresponding to the Input Data 44a' is compared with each 'characteristic in column 60a associated with the Historical Data 60' of the Logical Expressions and Algorithms 46/48. When a match (or a substantial match) is found between the 'Earth formation characteristics (associated
30 with a section of Earth Formation 'to be drilled') corresponding to the Input Data 44a'

and a 'characteristic in column 60a associated with the Historical Data 60', a 'Sequence of Drill Bits' (called a 'selected sequence of drill bits') corresponding to that 'characteristic in column 60a associated with the Historical Data 60' is generated as an output from the Logical Expressions and Algorithms block 46/48 in figure 14A. The
5 aforementioned 'selected sequence of drill bits along with other data associated with the selected sequence of drill bits' is generated as an 'output' by the Recorder or Display device 42b of the Computer System 42 in figure 12. See figure 15 for an example of that 'output'. The 'output' can be a 'display' (as illustrated in figure 15) that is displayed on a computer display screen, or it can be an 'output record' printed by the Recorder or
10 Display device 42b.

[00132] The functions discussed above with reference to figure 14A, pertaining to the manner by which the 'Logical Expressions and Algorithms' 46/48 will generate the 'Bit Selection Output Data' 42b1 in response to the 'Input Data' 44a, will be discussed in
15 greater detail below with reference to figure 14B.

[00133] In figure 14B, recall that the Input Data 44a represents a set of 'Earth formation characteristics', where the 'Earth formation characteristics' are comprised of data representing characteristics of a particular Earth formation 'To Be Drilled'. As a result,
20 the Input Data 44a is comprised of the following specific data: Measured Depth, Unconfined Compressive Strength, Casing Point Depth, Hole Size, Conductor, Casing Type Name, Casing Point, Day Rate Rig, Spread Rate Rig, and Hole Section Name.

[00134] In figure 14B, recall that the Logical Expressions 46 and Algorithms 48 will
25 respond to the Input Data 44a by generating a set of 'Bit Selection Output Data' 42b1, where the 'Bit Selection Output Data' 42b1 represents the aforementioned 'selected drill bit along with other data associated with the selected drill bit'. As a result, the 'Bit Selection Output Data' 42b1 is comprised of the following specific data: Measured Depth, Cumulative Unconfined Compressive Strength (UCS), Cumulative Excess UCS,
30 Bit Size, Bit Type, Start Depth, End Depth, Hole Section Begin Depth, Average UCS of

rock in section, Maximum UCS of bit, Bit Average UCS of rock in section, Footage, Statistical Drilled Footage for the bit, Ratio of footage drilled compared to statistical footage, Statistical Bit Hours, On Bottom Hours, Rate of Penetration (ROP), Statistical Bit Rate of Penetration (ROP), Mechanical drilling energy (UCS integrated over distance drilled by the bit), Weight On Bit, Revolutions per Minute (RPM), Statistical Bit RPM, Calculated Total Bit Revolutions, Time to Trip, Cumulative Excess as a ration to the Cumulative UCS, Bit Cost, and Hole Section Name.

[00135] In order to generate the 'Bit Selection Output Data' 42b1 in response to the 'Input Data' 44a, the Logical Expressions 46 and the Algorithms 48 must perform the following functions, which are set forth in the following paragraphs.

[00136] The Bit Selection Logical Expressions 46 will perform the following functions.

The Bit Selection Logical Expressions 46 will: (1) Verify the hole size and filter out the bit sizes that do not match the hole size, (2) Check if the bit is not drilling beyond the casing point, (3) Check the cumulative mechanical drilling energy for the bit run and compare it with the statistical mechanical drilling energy for that bit, and assign the proper risk to the bit run, (4) Check the cumulative bit revolutions and compare it with the statistical bit revolutions for that bit type and assign the proper risk to the bit run, (5) Verify that the encountered rock strength is not outside the range of rock strengths that is optimum for the selected bit type, and (6) Extend footage by 25% in case the casing point could be reached by the last selected bit.

[00137] The Bit Selection Algorithms 48 will perform the following functions. The Bit Selection Algorithms 48 will: (1) Read variables and constants, (2) Read catalogs, (3) Build cumulative rock strength curve from casing point to casing point, using the following equation:

$$CumUCS = \int_{start}^{end} (UCS) d ft ,$$

(4) Determine the required hole size, (5) Find the bit candidates that match the closest unconfined compressive strength of the rock to drill, (6) Determine the end depth of the bit by comparing the historical drilling energy with the cumulative rock strength curve for all bit candidates, (7) Calculate the cost per foot for each bit candidate taking into
 5 accounts the rig rate, trip speed and drilling rate of penetration by using the following equation:

$$TOT\ Cost = (RIG\ RATE + SPREAD\ RATE)(T_TripIn + \frac{footage}{ROP} + T_Trip) + Bit\ Cost$$

10 (8) Evaluate which bit candidate is most economic, (9) Calculate the remaining cumulative rock strength to casing point, (10) Repeat step 5 to 9 until the end of the hole section, (11) Build cumulative UCS, (12) Select bits – display bit performance and operating parameters, (13) Remove sub-optimum bits, and (14) Find the most economic bit based on cost per foot.

15

[00139] The following discussion set forth in the following paragraphs will describe how the ‘Automatic Well Planning Bit Selection software’ of the present invention will generate a ‘Selected Sequence of Drill Bits’ in response to ‘Input Data’.

20 [00140] The ‘Input Data’ is loaded, the ‘Input Data’ including the ‘trajectory’ data and Earth formation property data. The main characteristic of the Earth formation property data, which was loaded as input data, is the rock strength. The ‘Automatic Well Planning Bit Selection’ software of the present invention has calculated the casing points, and the number of ‘hole sizes’ is also known. The casing sizes are known and, therefore, the
 25 wellbore sizes are also known. The number of ‘hole sections’ are known, and the size of the ‘hole sections’ are also known. The drilling fluids are also known. The most important part of the ‘input data’ is the ‘hole section length’, the ‘hole section size’, and the ‘rock hardness’ (also known as the ‘Unconfined Compressive Strength’ or ‘UCS’) associated with the rock that exists in the hole sections. In addition, the ‘input data’
 30 includes ‘historical bit performance data’. The ‘Bit Assessment Catalogs’ include: bit

sizes, bit-types, and the relative performance of the bit types. The ‘historical bit performance data’ includes the footage that the bit drills associated with each bit-type. The ‘Automatic Well Planning Bit Selection software’ in accordance with the present invention starts by determining the average rock hardness that the bit-type can drill. The bit-types have been classified in the ‘International Association for Drilling Contractors (IADC)’ bit classification. Therefore, there exists a ‘classification’ for each ‘bit-type’. In accordance with one aspect of the present invention, we assign an ‘average UCS’ (that is, an ‘average rock strength’) to the bit-type. In addition, we assign a minimum and a maximum rock strength to each of the bit-types. Therefore, each ‘bit type’ has been assigned the following information: (1) the ‘softest rock that each bit type can drill’, (2) the ‘hardest rock that each bit type can drill’, and (3) the ‘average or the optimum hardness that each bit type can drill’. All ‘bit sizes’ associated with the ‘bit types’ are examined for the wellbore ‘hole section’ that will be drilled (electronically) when the ‘Automatic Well Planning Bit Selection software’ of the present invention is executed. Some ‘particular bit types’, from the Bit Selection Catalog, will filtered-out because those ‘particular bit types’ do not have the appropriate size for use in connection with the hole section that we are going to drill (electronically). As a result, a ‘list of bit candidates’ is generated. When the drilling of the rock (electronically – in the software) begins, for each foot of the rock, a ‘rock strength’ is defined, where the ‘rock strength’ has units of ‘pressure’ in ‘psi’. For each foot of rock that we (electronically) drill, the ‘Automatic Well Planning Bit Selection software’ of the present invention will perform a mathematical integration to determine the ‘cumulative rock strength’ by using the following equation:

$$CumUCS = \int_{start}^{end} (UCS) d \text{ ft}$$

where:

‘CumUCS’ is the ‘cumulative rock strength’, and

‘UCS’ (Unconfined Compressive Strength) is the ‘average rock strength’ per

‘bit candidate’, and

‘d’ is the drilling distance using that ‘bit candidate’.

[00141] Thus, if the ‘average rock strength/foot’ is 1000 psi/foot, and we drill 10 feet of rock, then, the ‘cumulative rock strength’ is $(1000 \text{ psi/foot})(10 \text{ feet}) = 10000 \text{ psi}$

5 ‘cumulative rock strength’. If the next 10 feet of rock has an ‘average rock strength/foot’ of 2000 psi/foot, that next 10 feet will take $(2000 \text{ psi/foot})(10 \text{ feet}) = 20000 \text{ psi}$

‘cumulative rock strength’; then, when we add the 10000 psi ‘cumulative rock strength’ that we already drilled, the resultant ‘cumulative rock strength’ for the 20 feet equals

30000 psi. Drilling (electronically – in the software) continues. At this point, compare

10 the 30000 psi ‘cumulative rock strength’ for the 20 feet of drilling with the ‘statistical performance of the bit’. For example, if, for a ‘particular bit’, the ‘statistical performance of the bit’ indicates that, statistically, ‘particular bit’ can drill fifty (50) feet in a

‘particular rock’, where the ‘particular rock’ has ‘rock strength’ of 1000 psi/foot. In that case, the ‘particular bit’ has a ‘statistical amount of energy that the particular bit is

15 capable of drilling’ which equals $(50 \text{ feet})(1000 \text{ psi/foot}) = 50000 \text{ psi}$. Compare the

previously calculated ‘cumulative rock strength’ of 30000 psi with the aforementioned ‘statistical amount of energy that the particular bit is capable of drilling’ of 50000 psi.

Even though ‘actual energy’ (the 30000 psi) was used to drill the first 20 feet of the rock, there still exists a ‘residual energy’ in the ‘particular bit’ (the ‘residual energy’ being the

20 difference between 50000 psi and 30000 psi). As a result, from 20 feet to 30 feet, we use

the ‘particular bit’ to drill once again (electronically – in the software) an additional 10

feet. Assume the ‘rock strength’ is 2000 psi. Determine the ‘cumulative rock strength’

by multiplying $(2000 \text{ psi/foot})(10 \text{ additional feet}) = 20000 \text{ psi}$. Therefore, the

‘cumulative rock strength’ for the additional 10 feet is 20000 psi. Add the 20000 psi

25 ‘cumulative rock strength’ (for the additional 10 feet) to the previously calculated 30000

psi ‘cumulative rock strength’ (for the first 20 feet) that we already drilled. The result

will yield a ‘resultant cumulative rock strength’ of 50000 psi’ associated with 30 feet of

drilling. Compare the aforementioned ‘resultant cumulative rock strength’ of 50000 psi

with the ‘statistical amount of energy that the particular bit is capable of drilling’ of

30 50000 psi. As a result, there is only one conclusion: the bit life of the ‘particular bit’ ends

and terminates at 50000 psi; and, in addition, the 'particular bit' can drill up to 30 feet. If the aforementioned 'particular bit' is 'bit candidate A', there is only one conclusion: 'bit candidate A' can drill 30 feet of rock. We now go to the next 'bit candidate' for the same size category and repeat the same process. We continue to drill (electronically – in the software) from point A to point B in the rock, and integrate the energy as previously described (as 'footage' in units of 'psi') until the life of the bit has terminated. The above mentioned process is repeated for each 'bit candidate' in the aforementioned 'list of bit candidates'. We now have the 'footage' computed (in units of psi) for each 'bit candidate' on the 'list of bit candidates'. The next step involves selecting which bit (among the 'list of bit candidates') is the 'optimum bit candidate'. One would think that the 'optimum bit candidate' would be the one with the maximum footage. However, how fast the bit drills (i.e., the Rate of Penetration or ROP) is also a factor. Therefore, a cost computation or economic analysis must be performed. In that economic analysis, when drilling, a rig is used, and, as a result, rig time is consumed which has a cost associated therewith, and a bit is also consumed which also has a certain cost associated therewith. If we (electronically) drill from point A to point B, it is necessary to first run into the hole where point A starts, and this consumes 'tripping time'. Then, drilling time is consumed. When (electronic) drilling is done, pull the bit out of the hole from point B to the surface, and additional rig time is also consumed. Thus, a 'total time in drilling' can be computed from point A to point B, that 'total time in drilling' being converted into 'dollars'. To those 'dollars', the bit cost is added. This calculation will yield: a 'total cost to drill that certain footage (from point A to B)'. The 'total cost to drill that certain footage (from point A to B)' is normalized by converting the 'total cost to drill that certain footage (from point A to B)' to a number which represents 'what it costs to drill one foot'. This operation is performed for each bit candidate. At this point, the following evaluation is performed: 'which bit candidate drills the cheapest per foot'. Of all the 'bit candidates' on the 'list of bit candidates', we select the 'most economic bit candidate'. Although we computed the cost to drill from point A to point B, it is now necessary to consider drilling to point C or point D in the hole. In that case, the Automatic Well Planning Bit Selection software will conduct the same steps as previously described by

evaluating which bit candidate is the most suitable in terms of energy potential to drill that hole section; and, in addition, the software will perform an economic evaluation to determine which bit candidate is the cheapest. As a result, when (electronically) drilling from point A to point B to point C, the 'Automatic Well Planning Bit Selection software' of the present invention will perform the following functions: (1) determine if 'one or two or more bits' are necessary to satisfy the requirements to drill each hole section, and, responsive thereto, (2) select the 'optimum bit candidates' associated with the 'one or two or more bits' for each hole section.

[00142] In connection with the Bit Selection Catalogs 52, the Catalogs 52 include a 'list of bit candidates'. The 'Automatic Well Planning Bit Selection software' of the present invention will disregard certain bit candidates based on: the classification of each bit candidate and the minimum and maximum rock strength that the bit candidate can handle. In addition, the software will disregard the bit candidates which are not serving our purpose in terms of (electronically) drill from point A to point B. If rocks are encountered which have a UCS which exceeds the UCS rating for that 'particular bit candidate', that 'particular bit candidate' will not qualify. In addition, if the rock strength is considerably less than the minimum rock strength for that 'particular bit candidate', disregard that 'particular bit candidate'.

[00143] In connection with the Input Data 44a, the Input Data 44a includes the following data: which hole section to drill, where the hole starts and where it stops, the length of the entire hole, the size of the hole in order to determine the correct size of the bit, and the rock strength (UCS) for each foot of the hole section. In addition, for each foot of rock being drilled, the following data is known: the rock strength (UCS), the trip speed, the footage that a bit drills, the minimum and maximum UCS for which that the bit is designed, the Rate of Penetration (ROP), and the drilling performance. When selecting the bit candidates, the 'historical performance' of the 'bit candidate' in terms of Rate of Penetration (ROP) is known. The drilling parameters are known, such as the 'weight on bit' or WOB, and the Revolutions per Minute (RPM) to turn the bit is also known.

[00144] In connection with the Bit Selection Output Data 42b1, since each bit drills a hole section, the output data includes a start point and an end point in the hole section for each bit. The difference between the start point and the end point is the 'distance that the bit will drill'. Therefore, the output data further includes the 'distance that the drill bit will drill'. In addition, the output data includes: the 'performance of the bit in terms of Rate of Penetration (ROP)' and the 'bit cost'.

[00145] In summary, the Automatic Well Planning Bit Selection software 42c1 will: (1) suggest the right type of bit for the right formation, (2) determine longevity for each bit, (3) determine how far can that bit drill, and (3) determine and generate 'bit performance' data based on historical data for each bit.

[00146] Referring to figure 15, the 'Automatic Well Planning Bit Selection Software' 42c1 will generate the display illustrated in figure 15, the display of figure 15 illustrating 'Bit Selection Output Data 42b1' representing the selected sequence of drill bits which are selected by the 'Automatic Well Planning Bit Selection Software' 42c1.

Automatic Well Planning Software System – Drill string Design sub-task 14b

[00147] In figure 8, the Drillstring Design sub-task 14b is illustrated.

[00148] Designing a drillstring is not terribly complex, but it is very tedious. The sheer number of components, methods, and calculations required to ensure the mechanical suitability of stacking one component on top of another component is quite cumbersome. Add to this fact that a different drillstring is created for every hole section and often every different bit run in the drilling of a well and the amount of work involved can be large and prone to human error.

[00149] The 'Automatic Well Planning Drillstring Design software' of the present invention includes an algorithm for automatically generating the required drillstrings to

support the weight requirements of each bit, the directional requirements of the trajectory, the mechanical requirements of the rig and drill pipe, and other general requirements for the well, i.e. formation evaluation. The resulting drillstrings are accurate enough representations to facilitate calculations of frictional pressure losses (hydraulics), mechanical friction (torque & drag), and cost (BHA components for directional drilling and formation evaluation).

[00150] Referring to figure 16, a Computer System 62 is illustrated. The Computer System 62 includes a Processor 62a connected to a system bus, a Recorder or Display Device 62b connected to the system bus, and a Memory or Program Storage Device 62c connected to the system bus. The Recorder or Display Device 62b is adapted to display 'Drillstring Design Output Data' 62b1. The Memory or Program Storage Device 62c is adapted to store an 'Automatic Well Planning Drillstring Design Software' 62c1. The 'Automatic Well Planning Drillstring Design Software' 62c1 is originally stored on another 'program storage device', such as a hard disk; however, the hard disk was inserted into the Computer System 62 and the 'Automatic Well Planning Drillstring Design Software' 62c1 was loaded from the hard disk into the Memory or Program Storage Device 62c of the Computer System 62 of figure 16. In addition, a Storage Medium 64 containing a plurality of 'Input Data' 64a is adapted to be connected to the system bus of the Computer System 62, the 'Input Data' 64a being accessible to the Processor 62a of the Computer System 62 when the Storage Medium 64 is connected to the system bus of the Computer System 62. In operation, the Processor 62a of the Computer System 62 will execute the Automatic Well Planning Drillstring Design Software 62c1 stored in the Memory or Program Storage Device 62c of the Computer System 62 while, simultaneously, using the 'Input Data' 64a stored in the Storage Medium 64 during that execution. When the Processor 62a completes the execution of the Automatic Well Planning Drillstring Design Software 62c1 stored in the Memory or Program Storage Device 62c (while using the 'Input Data' 64a), the Recorder or Display Device 62b will record or display the 'Drillstring Design Output Data' 62b1, as shown in figure 16. For example the 'Drillstring Design Output Data' 62b1 can be displayed on a

display screen of the Computer System 62, or the 'Drillstring Design Output Data' 62b1 can be recorded on a printout which is generated by the Computer System 62. The 'Input Data' 64a and the 'Drillstring Design Output Data' 62b1 will be discussed and specifically identified in the following paragraphs of this specification. The 'Automatic Well Planning Drillstring Design software' 62c1 will also be discussed in the following paragraphs of this specification. The Computer System 62 of figure 16 may be a personal computer (PC). The Memory or Program Storage Device 62c is a computer readable medium or a program storage device which is readable by a machine, such as the processor 62a. The processor 62a may be, for example, a microprocessor, a microcontroller, or a mainframe or workstation processor. The Memory or Program Storage Device 62c, which stores the 'Automatic Well Planning Drillstring design Software' 62c1, may be, for example, a hard disk, ROM, CD-ROM, DRAM, or other RAM, flash memory, magnetic storage, optical storage, registers, or other volatile and/or non-volatile memory.

[00151] Referring to figure 17, a detailed construction of the 'Automatic Well Planning Drillstring Design Software' 62c1 of figure 16 is illustrated. In figure 17, the 'Automatic Well Planning Drillstring Design Software' 62c1 includes a first block which stores the Input Data 64a, a second block 66 which stores a plurality of Drillstring Design Logical Expressions 66; a third block 68 which stores a plurality of Drillstring Design Algorithms 68, a fourth block 70 which stores a plurality of Drillstring Design Constants 70, and a fifth block 72 which stores a plurality of Drillstring Design Catalogs 72. The Drillstring Design Constants 70 include values which are used as input for the Drillstring Design Algorithms 68 and the Drillstring Design Logical Expressions 66. The Drillstring Design Catalogs 72 include look-up values which are used as input by the Drillstring Design Algorithms 68 and the Drillstring Design Logical Expressions 66. The 'Input Data' 64a includes values which are used as input for the Drillstring Design Algorithms 68 and the Drillstring Design Logical Expressions 66. The 'Drillstring Design Output Data' 62b1 includes values which are computed by the Drillstring Design Algorithms 68 and which result from the Drillstring Design Logical Expressions 66. In operation, referring to

figures 16 and 17, the Processor 62a of the Computer System 62 of figure 16 executes the Automatic Well Planning Drillstring Design Software 62c1 by executing the Drillstring Design Logical Expressions 66 and the Drillstring Design Algorithms 68 of the Drillstring design Software 62c1 while, simultaneously, using the 'Input Data' 64a, the
5 Drillstring Design Constants 70, and the values stored in the Drillstring Design Catalogs 72 as 'input data' for the Drillstring Design Logical Expressions 66 and the Drillstring Design Algorithms 68 during that execution. When that execution by the Processor 62a of the Drillstring Design Logical Expressions 66 and the Drillstring Design Algorithms 68 (while using the 'Input Data' 64a, Constants 70, and Catalogs 72) is completed, the
10 'Drillstring Design Output Data' 62b1 will be generated as a 'result'. The 'Drillstring Design Output Data' 62b1 is recorded or displayed on the Recorder or Display Device 62b of the Computer System 62 of figure 16. In addition, that 'Drillstring Design Output Data' 62b1 can be manually input, by an operator, to the Drillstring Design Logical Expressions block 66 and the Drillstring Design Algorithms block 68 via a 'Manual
15 Input' block 74 shown in figure 17.

Input Data 64a

[00152] The following paragraphs will set forth the 'Input Data' 64a which is used by the
20 'Drillstring Design Logical Expressions' 66 and the 'Drillstring Design Algorithms' 68. Values of the Input Data 64a that are used as input for the Drillstring Design Algorithms 68 and the Drillstring Design Logical Expressions 66 include the following:

- 25 (1) Measured Depth
- (2) True Vertical Depth
- (3) Weight On Bit
- (4) Mud Weight
- (5) Mud Weight Measured Depth
- (6) Inclination
- 30 (7) Casing Point Depth
- (8) Hole Size
- (9) Footage
- (10) ROP
- (11) Time to Trip
- 35 (12) Dog Leg Severity

	(13) True Vertical Depth
	(14) Pore Pressure without Safety Margin
	(15) Bit Size
5	(16) Upper Wellbore Stability Limit
	(17) Lower Wellbore Stability Limit
	(18) Openhole Or Cased hole completion
	(19) BOP Location
	(20) Casing Type Name
	(21) Hole Section Name
10	(22) Conductor
	(23) Start Depth
	(24) End Depth
	(25) On Bottom Hours
	(26) Statistical Drilled Footage for the bit
15	(27) Cumulative UCS
	(28) Casing Point
	(29) Casing Size
	(30) Casing Burst Pressure
	(31) Casing Collapse Pressure
20	(32) Casing Connector
	(33) Casing Cost
	(34) Casing Grade
	(35) Casing Weight per foot
	(36) Casing Outer Diameter
25	(37) Casing Internal Diameter
	(38) Air Gap
	(39) Casing Top Measure Depth
	(40) Water Depth
	(41) Top of Tail slurry
30	(42) Top Of Cement
	(43) Mud Volume
	(44) Offshore Well

Drillstring Design Constants 70

35

[00153] The 'Drillstring Design Constants' 70 are used by the 'Drillstring Design Logical Expressions' 66 and the 'Drillstring Design Algorithms' 68. The values of the 'Drillstring Design Constants 70 that are used as input data for Drillstring Design Algorithms 68 and the Drillstring Design Logical Expressions 66 include the following:

- 5
- (1) Design Factor
 - (2) Stand Length
 - (3) Safety Margin Kick Tolerance
 - (4) Minimum well inclination flag
 - (5) Minimum well dogleg severity flag
 - (6) Gravitation constant
 - (7) Mud surface volume

10 Drillstring Design Catalogs 72

[00154] The 'Drillstring Design Catalogs' 72 are used by the 'Drillstring Design Logical Expressions' 66 and the 'Drillstring Design Algorithms' 68. The values of the Catalogs 72 that are used as input data for Drillstring Design Algorithms 68 and the Drillstring

15 Design Logical Expressions 66 include the following:

- 20
- (1) Drill Pipe Catalog
 - (2) Drill Collar Catalog File
 - (3) Heavy Weight Drill Pipe Catalog File
 - (4) Drill Pipe Catalog File
 - (5) BHA Catalog File
 - (6) Required overpull

Drillstring Design Output Data 62b1

25

[00155] The 'Drillstring Design Output Data' 62b1 is generated by the 'Drillstring Design Algorithms' 68. The 'Drillstring Design Output Data' 62b1, that is generated by the 'Drillstring Design Algorithms' 68, includes the following types of output data:

- 30
- (1) Hole Section Begin Depth
 - (2) Drill Collar 1 Length
 - (3) Drill Collar 1 Weight
 - (4) Drill Collar 1
 - (5) Drill Collar 1 OD
 - 35 (6) Drill Collar 1 ID
 - (7) Drill Collar 2 Length

- (8) Drill Collar 2 Weight
- (9) Drill Collar 2
- (10) Drill Collar 2 OD
- (11) Drill Collar 2 ID
- 5 (12) Heavy Weight Length
- (13) Heavy Weight Weight
- (14) Heavy Weight
- (15) Heavy Weight OD
- (16) Heavy Weight ID
- 10 (17) Drill Pipe Length
- (18) Drill Pipe Weight
- (19) Pipe
- (20) Pipe OD
- (21) Pipe ID
- 15 (22) Drill Pipe Tensile Rating
- (23) BHA tools
- (24) Duration
- (25) Kick Tolerance
- (26) Drill Collar 1 Linear Weight
- 20 (27) Drill Collar 2 Linear Weight
- (28) Heavy Weight Linear Weight
- (29) Drill Pipe Linear Weight
- (30) DC OD
- (31) DC ID
- 25 (32) DC Linear Weight
- (33) HW OD
- (34) HW ID
- (35) HW Linear Weight
- (36) DP OD
- 30 (37) DP ID
- (38) DP Linear Weight

Drillstring Design Logical Expressions 66

- 35 [00156] The following paragraphs will set forth the ‘Drillstring Design Logical Expressions’ 66. The ‘Drillstring Design Logical Expressions’ 66 will: (1) receive the ‘Input Data 64a’, including a ‘plurality of Input Data calculation results’ that has been generated by the ‘Input Data 64a’; and (2) evaluate the ‘Input Data calculation results’ during the processing of the ‘Input Data’ 64a. A better understanding of the following
- 40 ‘Drillstring Design Logical Expressions 66’ will be obtained in the paragraphs to follow when a ‘functional description of the operation of the present invention’ is presented.

[00157] The Drillstring Design Logical Expressions 66, which evaluate the processing of the Input Data 64a, include the following:

- 5 Check that all drill string components will fit into the wellbore geometry, including after manual alteration of component size.

- 10 The first stand consists of a combination of a Positive Displacement Motor (PDM), a Measurement While Drilling (MWD) device, a Logging While Drilling (LWD) tool, and/or drill collars, and is named DC1. The actual configuration is based on the maximum inclination and dogleg severity in the hole section, using the following rules:
- (1) A PDM is required when the inclination and dogleg exceed the threshold values.
 - (2) A MWD is required when the PDM is selected.
 - 15 (3) A LWD is suggested in the last hole section

Drillstring Design Algorithms 68

- [00158] The following paragraphs will set forth the 'Drillstring Design Algorithms' 68.
- 20 The 'Drillstring Design Algorithms' 68 will receive the output from the 'Drillstring Design Logical Expressions' 66 and process that 'output from the Drillstring Design Logical Expressions 66' in the following manner. DC is an acronym for 'Drill Collar', HW is an acronym for 'Heavy Weight', and DP is an acronym for 'Drill Pipe'. DC1 is 'Drill Collar 1', and DC2 is 'Drill Collar 2'. A better understanding of the following
- 25 'Drillstring Design Algorithms 68' will be obtained in the paragraphs to follow when a 'functional description of the operation of the present invention' is presented. In the following, DF is a 'design factor' and 'WFT' is a 'weight/foot'.

- (1) Read variables and constants;
- 30 (2) Read catalogs;
- (3) Determine Outer Diameter DC1, DC2, HW and DP:

- (a) DC1 Outer diameter is obtained from table by using the Hole Size,
 (b) DP,

Use **Stiffness Ratio** to Determine the Outer Diameter.

DP_{OD} = Obtained from table by using the Hole Size (Bit Diameter)

5

$$DP_{OD} \leq DC1_{OD},$$

- (c) DC2,

Use **Stiffness Ratio** to Determine the Outer Diameter.

$$SR = Z_{BIG}/Z_{SMALL}$$

$$Z = (\pi/32) ((OD^4 - ID^4) / OD)$$

10

$$SR < 3.5$$

$$DC2_{OD} \leq DC1_{OD} \text{ \& } DC2_{OD} \geq DP_{OD},$$

- (d) HW,

Use **Stiffness Ratio** to Determine the Outer Diameter.

$$SR = Z_{BIG}/Z_{SMALL}$$

15

$$Z = (\pi/32) ((OD^4 - ID^4) / OD)$$

$$SR < 3.5$$

$$HW_{OD} \leq DC2_{OD} \text{ \& } HW_{OD} \geq DP_{OD},$$

- (e) DP_{OD} ≤ HW_{OD};

- (4) Determine the maximum weight on bit used in the hole section;

20

- (5) Determine Weight of DC1, DC2 and HW, where 'θ' is used for the wellbore inclination, and 'DF' is the Design Factor:

$$HW_w = \frac{WOB(DF)}{K_b * \cos(\theta)} \left(\frac{5 + \theta}{100} \right),$$

25

$$DC1_w + DC2_w = \frac{WOB(DF)}{K_b * \cos(\theta)} \left(\frac{95 - \theta}{100} \right), \text{ or}$$

$$DC1_w + DC2_w = \frac{WOB(DF)}{K_b * \cos(\theta)} - HW_w,$$

30

$$DC1_w = DC1_L * DC1_{WFT},$$

$$DC2_w = (DC1 + DC2) - DC1;$$

(6) Determine Length of DC1, DC2, HW, DP:

5 (a) $DC1 - DC1_L = 90 \text{ Feet} = 1 \text{ Stand} = 3 \text{ Joint},$

(b) $DC2 - DC2_L = DC2_w / DC2_{wFT},$

10 (c) $HW - HW_L = HW_w / HW_{wFT},$

(d) $DP - DP_L = (\text{Bit Section Length}) - (DC1_L - DC2_L - HW_L);$

(7) Determine the tensile Risk:

15 (a) Take the rating of the top most Drill Pipe (Premium 80%),

(b) $\text{Tensile Risk} = ((\sum(W_{\text{Components}}) * K_b) + \text{Min. Overpull}) / (\text{Pipe Tensile Rating} * 0.8);$

20 (8) Calculate cost, based on the duration to drill the section; and

(9) Calculate the kick tolerance volume and assign risk based on the well type.

25 [00159] Refer to figure 18 which will be used during the following functional description.

[00160] In figure 18, the Input Data 76 includes the 'Input Data' 64a, the Constants 70, and the Catalogs 72. The Input Data 76 will be provided as 'input data' to the Drillstring Design Logical Expressions 66. The Drillstring Design Logical Expressions 66 will:

30 check that all drillstring components will fit into the wellbore geometry, and determine whether LWD or MWD measurement tools are needed for the hole being drilled. Then, the Drillstring Design Algorithms 68 will: determine the outer diameter for Drill Collar 1 (DC1), Drill Collar 2 (DC2), the Heavy Weights (HW), and the Drill Pipe (DP); determine the maximum 'Weight on Bit' in the hole section; determine the weight of

35 DC1, DC2, and HW; determine the length of DC1, DC2, HW, and DP; determine the tensile risk; calculate the cost based on duration of the drill in the section; and calculate the kick tolerance. Then, the Drillstring Design Output Data 62b1 will be generated and recorded or displayed on the 'recorder or display device' 62b in figure 16, the Drillstring

Design Output Data 62b1 including: a summary of the drill string in each hole section, where that summary includes (1) size and weight and length of each components in the drill string, and (2) what tools (e.g., LWD, and MWD) exist in the drill string. A better understanding of the above referenced 'Drillstring Design Algorithms 68' will be
5 obtained in connection with the 'functional description of the operation of the present invention' which is presented in the following paragraphs.

[00161] Referring to figure 19, a typical 'Drillstring Design output display' is illustrated which can be recorded or displayed on the recorder or display device 62b of figure 16 and
10 which displays the Drillstring Design Output Data 62b1 in figure 16.

[00162] A functional description of the operation of the 'Automatic Well Planning Drillstring Design Software' 62c1 of the present invention will be set forth in the following paragraphs with reference to figures 1 through 19 of the drawings.

15 [00163] In the order of the workflow in figure 8, we know the wellbore 'hole size' and we know where the hole starts and where it finishes. The drill bits have been selected, and, from the drill bit, we know the drilling parameters, such as, how much 'weight on bit' is required to drill that bit, and how many revolutions per minute (RPM) are required
20 to spin that bit. The last engineering task is the hydraulics task. This is the task where, based on the rate of penetration (ROP) for the particular drill bit, it is necessary to determine how much fluid do we need to pump in order to clean the hole free of cuttings. The hydraulics task reflects the 'pressure losses', and, in order to calculate the 'pressure losses', we need to know the structure of the drill string. As a result, drill string design
25 takes place after bit selection and before hydraulics. From the bit selection, we know the sizes of the drill bits that are being used, we know how much 'weight on bit' is required for that particular bit, and we know, from the wellbore geometry, the casing size. All of the drill string components must be smaller than the drill bit size because all of the drill string components will be lowered into a newly drilled wellbore, and there needs to be

sufficient room for the cuttings to be transported up to the surface between the wellbore and the Bottom Hole Assembly (BHA) components of the drillstring.

[00164] Recall the drillstring and compare the drillstring with an injection needle.

- 5 Recalling the depths that are being drilled (e.g., 20,000 feet) using a five-inch Drill Pipe (DP), comparing these dimensions, by analogy, with the injection needle, it would appear that the injection needle should be approximately 20 feet long. The drillstring is a very flexible hollow tube, since it is so much longer than the other dimensions of the drillstring pipe. The drillstring extends from a surface pipe to a bit pipe located
- 10 downhole. The surface pipe is a common pipe, such as a five (5) inch pipe. If we are drilling a seventeen and one half (17-1/2) inch wellbore, different components of the drillstring are needed to extend the drillstring from a 5 inch diameter surface pipe to a 17-1/2 inch drill bit located downhole. Although most of the drillstring is in tension, we still need to have a 'weight on bit'. Therefore, we need to include 'components' in the
- 15 drillstring which have a 'high-density' or a 'high-weight' that are located near to the drill bit, since those 'components' are in 'compression'. Those drillstring 'components' that are located near to the drill bit need to be 'stiffer' and therefore the outer diameter of those 'components' must have an outer diameter (OD) which is larger than the OD of the surface pipe (that is, the OD of the surface pipe is smaller than the OD of the
- 20 'components' near the drill bit). As a result, the 'components' located near the drill bit have a 'high-weight' and therefore a 'high outer diameter' (certainly higher than the surface pipe).

- [00165] However, at an interface between a big OD pipe located near the drill bit
- 25 (hereinafter called a 'drill collar' or 'DC') and a much smaller OD drill pipe (DP) located near the surface, a great deal of tension will accumulate (called, the 'stress bending ratio'). Therefore, a 'transition' is required between the big-OD drill collar located near the drill bit and the 'smaller-OD' drill pipe located near the surface. In order provide for the aforementioned 'transition', two different sizes of 'big-OD' drill collars are used; that
- 30 is, Drill Collar 1 (DC1) and Drill Collar 2 (DC2). Between the Drill Collar 2 (DC2) and

the 'smaller OD' drill pipe located near the surface, one more 'additional transition' is needed, and that 'additional transition' is called a 'heavy-weight' drill pipe or 'HW' drill pipe'. The HW drill pipe is the same in size relative to the 'smaller OD' drill pipe; however, the HW drill pipe has a smaller inner diameter (ID). As a result, the HW drill pipe is heavier than the 'smaller OD' drill pipe. This helps in producing a smooth 'stress transition' between a big OD pipe at the bottom of the wellbore and a smaller OD pipe at the surface of the wellbore. The 'stress bending ratio' (which must be a certain number) can be calculated, and, if that 'stress bending ratio' number is within certain limits, the aforementioned 'stress transition' (between the big OD pipe at the bottom of the wellbore and the smaller OD pipe at the surface of the wellbore) is smooth.

[00166] The drill bits must have a 'weight on bit' and that is delivered by the weights of the drill collars. The drill collars must fit within the open-hole size, therefore, the maximum size of the drill collars can be calculated. When the maximum size of the drill collars are known, we would know the number of 'pounds per foot' or 'weight' of the (drill collar) pipes. When one knows the amount of weight that is required to drill, we can back-calculate the length of the drill collars. In addition, we can also calculate the length of the heavy-weight 'HW' drill pipe that must be run into the wellbore in order to provide the aforementioned 'weight on bit'. The drill pipe (DP) located near the surface is not delivering any 'weight on bit' for the drill bit, however, the drill pipe (DP) is needed to provide a flow-path for fluids produced from downhole.

[00167] All of these drill-collar components, which hang off the drill pipes in the wellbore, are heavy. As a result, there exists a 'tension factor' pulling on the last drill pipe at the surface of the wellbore. Since the drill pipe at the surface of the wellbore can only handle a certain tension, one can calculate the 'applied or actual tension' and compare that 'applied or actual tension' with the 'available tension' or the 'designed tension'. That comparison can be expressed as a 'ratio'. As long as the 'available tension' is higher than the 'applied or actual tension', the 'ratio' is larger than '1'. If the 'available tension' is not higher than the 'applied or actual tension', that is, if the 'tension

applied' is actually larger than the 'tension which the drill pipe possesses as a material characteristic', the 'ratio' will be smaller than '1' and consequently the pipe will break.

[00168] In addition, if we drill other than vertically in an Earth formation, special tools
5 are needed. While drilling, if we need to turn the drillstring a certain 'degree' in a
horizontal plane (such as, turning the drillstring from a north direction to an east
direction), the aforementioned 'degree' of 'turn' of the drill string downhole is called an
'inclination'. A motor (called a Positive Displacement Motor, or PDM) is needed to
make the 'turn'. Therefore, when a change of 'inclination' is needed, a motor is needed
10 to produce that change of 'inclination'. When the motor is being used to produce that
change of 'inclination', at any point in time, we need to know the 'direction' in which the
motor is drilling and that 'direction' must be compared with a 'desired direction'. In
order to measure the 'direction' of the motor, and therefore, the 'direction' of the drill bit,
a 'measurement device' is needed, and that 'measurement device' is called an 'MWD' or
15 a 'Measurement While Drilling' measurement device. The 'Algorithm' 68 associated
with the 'Automatic Well Planning Drillstring Design software' 62c1 present invention
knows that, if the drill bit is drilling 'directionally', a PDM motor is needed and an MWD
measurement device is also needed.

[00169] Another logging tool is used, which is known as 'LWD' or 'Logging While
20 Drilling'. In certain wellbore 'hole sections', it is advantageous to include an 'LWD'
logging tool in the tool string. In connection with the 'Algorithm' 68 of the present
invention, in the last hole section of a wellbore being drilled (known as the 'production
hole section'), a maximum number of measurements is desired. When a maximum
25 number of measurements is needed in the last hole section of the wellbore being drilled,
the 'LWD' tool is utilized. Therefore, in connection with the logic of the 'Algorithm' 68
of the present invention, the 'trajectory' of the wellbore being drilled is measured, and the
'hole sections' of the wellbore being drilled are noted. Depending on the 'hole section'
in the wellbore where the drill bit is drilling the wellbore, and depending on the
30 'trajectory' and the 'inclination' and an 'azimuth' change, certain 'drillstring

components' are recommended for use, and those 'drillstring components' include the Measurement While Drilling (MWD) measurement device, the Logging While Drilling (LWD) tool, and the Positive Displacement Motor (PDM).

5 [00170] Therefore, we know: (1) the 'weight on bit' that the drill bit requires, (2) the size of the bit, (3) the wellbore geometry, (4) the size of the 'drillstring components', (5) the 'trajectory' of the 'hole section', (6) whether we need certain measurement tools (such as MWD and LWD), (7) the size of those measurement tools, and (8) the size of the drill pipe (since it has a rating characteristic). A Drillstring Design Algorithm 68 of the
10 present invention computes the size of the smaller drillstring components (located near the surface) in order to provide a smooth stress transition from the drill bit components (located downhole) to the smaller components (located near the surface).

[00171] In connection with the Drillstring Design Output Data 62b1 of figure 17 which is
15 generated by the Drillstring Design Algorithm 68, since we use drill pipe, the Drillstring Design Output Data 62b1 includes: (1) the size of the drill pipe, (2) the length of the drill pipe (including the heavy weight drill pipe), (3) the size and the length of the drill collars, and (4) the identity and the size and the length of any PDM or MWD or LWD tools that are utilized. In connection with all of the aforementioned PDM and MWD and LWD
20 'components', we also know the weight of these 'components'. Therefore, we can compute the 'total tension' on the drill string, and we compare the computed 'total tension' with 'another tension' which represents a known tension rating that the drill string is capable of handling.

25 [00172] The 'Input Data' 64 of figure 17 includes: (1) the trajectory, (2) the wellbore geometry including the casing size and the hole size, (3) the inclination associated with the trajectory, and (4) the drilling parameters associated with the drill bit that was previously selected.

[00173] The Drillstring Design Catalogs 70 of figure 17 include: the sizes of all the Drillstring components, and the OD and the ID and the linear weight per foot, and the tension characteristics (the metal characteristics) associated with these Drillstring components.

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[00174] The Constants 70 of figure 17 include: Gravitational constants and the length of one drilling stand.

[00175] The Logical Expressions 66 of figure 17 will indicate whether we need the measurement tools (LWD, MWD) in connection with a particular wellbore to be drilled. In addition, the rules in the Logical Expressions 66 are compared with the actual 'trajectory' of the drill bit in a hole section when drilling a deviated wellbore. In addition, the hole sections in the wellbore being drilled are compared with the requirements of those hole sections. For example, in a production hole section, an LWD tool is suggested for use. In hole sections associated with a directional well, a PDM motor and an LWD tool is suggested for use. In addition, the Logical Expressions 66 indicate that, if these PDM or LWD or MWD components are used, it is necessary to pay for such components. That is, the PDM and LWD and MWD components must be rented. Therefore, in the Logical Expressions 66, a cost/day is assigned, or, alternatively, a cost/foot.

20

[00176] In connection with the Drillstring Design Algorithms 68, a 'smooth transition' in size from the larger size pipe at the bottom near the bit to the smaller size pipe at the surface is provided; and, from the drill bit, we know, for each bit, how much 'weight on bit' that bit requires. That weight is delivered by the DC1, and the DC2 and the HW (heavy weights). Therefore, for each component, we must determine what length we need to have in order to provide that 'weight on bit'. If we are drilling a vertical well, all components are hanging. One factor associated with a vertical wellbore is that the entire weight of the drill string is hanging from all those components. However, if the well is deviated (such as 45 degrees), about 30% of the weight is lost. When drilling inside a

25

certain inclination, longer drillstring components are required in order to provide the same weight. Therefore, the Algorithm 68 corrects for the inclination.

[00177] In connection with the 'tensile risk', if we know the total weight that is hanging
5 on the drill pipe, we also need to know the 'tensile capacity' that the drill pipe has at the surface. As a result, we compare the 'total tension' with the 'maximum allowable (or potential) tension'. If the 'total tension' and the 'maximum allowable (or potential) tension' are expressed as a 'ratio', as the 'ratio' approaches '1', the greater the likelihood that the pipe will fail. Therefore, in connection with 'tensile risk', we compute the
10 'amount of tension applied', and compare that with the 'maximum allowable tension to be applied'.

[00178] In connection with cost, drill pipes and drill collars come with a rig, and we already paid for the rig on a per-day basis. If we need the specialized tools (e.g., PDM or
15 MWD or LWD), we need to rent those tools, and the rental fee is paid on a daily basis. We need to compute how long we are going to use those tools for each drill section. If we know the time in days, we can calculate how much we need to pay. If we use a PDM motor, for example, a back up tool is needed for stand by. The stand by tool is paid at a lower rate.

[00179] In connection with the kick tolerance, the 'kick tolerance' is a volume of gas that can flow into the wellbore without any devastating effects. We can handle gas flowing into the well as long as the gas has a small volume. We can compute the 'volume' of gas that we can still safely handle and that volume is called the 'kick tolerance'. When
25 computing the 'volume', during volumetric calculations, the 'volume' depends on: (a) hole size, and (b) the components in the drill string, such as the OD of the drill collars, the OD of the drill pipe, and the HW and the hole size. The 'kick tolerance' takes into account the pore pressure and the fracture pressure and the inclination and the geometric configuration of the drill string. The Drillstring Design Algorithm 68 receives the pore
30 pressure and the fracture pressure and the inclination and the geometric configuration of

the drill string, and computes the 'volume of gas' that we can safely handle. That 'volume of gas' is compared with the 'well type'. Exploration wells and development wells have different tolerances for the 'maximum volume' that such wells can handle.

- 5 [00180] Therefore, the 'Automatic Well Planning Drillstring Design software' 62c1 receives as 'input data': the trajectory and the wellbore geometry and the drilling parameters, the drilling parameters meaning the 'weight on bit'. When the software 62c1 is executed by the processor 62a of the computer system of figure 16, the 'Automatic Well Planning Drillstring Design software' 62c1 will generate as 'output data':
- 10 information pertaining to the drill string 'components' that are needed, a description of those 'components', such as the Outer Diameter (OD), the Inner Diameter (ID), the linear weight, the total weight, and the length of those 'components', the kick tolerance and the tensile risk. In particular, the Drillstring Design Output Data 62b1 includes a 'summary of the drill string in each hole section'; that is, from top to bottom, the 'summary of the
- 15 drill string in each hole section' includes: the size and the length of the drill pipe, the size and the weight of the heavy weight (HW) drill pipe, the size and the weight of the Drill Collar 2 (DC2), the size and the weight of the Drill Collar 1 (DC1), and the identity of other tools that are needed in the drill string (e.g., do we need to have: a PDM, or a LWD, or an MWD in the drill string). For each 'component' in the drillstring, the following
- 20 information is reported: the inner diameter, the length/weight, the total weight for each 'component', the kick tolerance (that volume of gas that we can safely handle).

- [00181] A functional specification associated with the Automatic Well Planning Drillstring Design Software 62c1 of the present invention will be set forth in the
- 25 following paragraphs.

Select Bottom Hole Assembly (BHA) Configuration

Characteristic Information

Goal In Context:	This use case describes the process to select BHA
Scope:	Select BHA
Level:	Task
Pre-Condition:	The user has selected bits.
Success End Condition:	The system confirms to the user that the BHA has been selected successfully.
Failed End Condition:	The system informs the user that the BHA is not selected due to failure in calculation.
Primary Actor:	The User
Trigger Event:	The use completed the bit selection.

5

Main Success Scenario

<u>Step</u>	<u>Actor Action</u>	<u>System Response</u>
1	The user accepts the bit selection.	<p>The system generates one BHA configuration per hole section, based on the bit section runs, casing points, casing and hole size, the well trajectory and rock type.</p> <p>The BHA configuration includes the downhole tools (PDM, MWD, LWD) and amount of DC's, HWDP and size of DP.</p> <p>The design will use the drill pipe size from the rig properties and the performance of that pipe is available in the catalog. The required WOB taken from the bit selection task. The system will also calculate the available WOB, position of neutral point, overpull limits, buckling limits and bending stress ratios and displays them in the GUI.</p> <p>The system lists the BHA and drill string configuration and sizes in a GUI and displays the drillstring in the wellbore schematic.</p> <p>The system also calculates kick tolerance per hole</p>

- | | | |
|---|---|--|
| | | section and displays the results in the grid and plots. |
| 2 | The user modifies BHA components, OD, ID, Length or linear weight | The system recalculates the drillstring weight, MOP, tensile risk, and kick tolerance. |
| 3 | The user accepts the BHA design | |

Scenario Extensions

<u>Step</u>	<u>Condition</u>	<u>Action Description</u>
1a	The system fails to generate a basic BHA configuration. The user makes the appropriate corrections.	The system informs the user of the failure and its reasons. The user re-joins Step 2.
1b	The user-selected configuration violates the constraints. The user makes the appropriate correction.	The system informs the user of the violation. The user re-joins Step 2.

5

Scenario Variations

<u>Step</u>	<u>Variable</u>	<u>Possible Variations</u>
1	The user modifies and accepts the suggested BHA downhole tools like PDM, MWD and LWD (based on business rules).	The system updates the BHA configuration.
1	The user modifies and accepts the amount of DC's, HWDP and their sizes.	The system updates the BHA configuration based on the user's modifications and confirms to the user that the BHA configuration has been saved successfully. The use case ends successfully.

Related Information

Schedule:	Version 1.1
Priority:	P1
Performance Target:	N/A
Frequency:	N/A
Super Use Case:	Swordfish Use Case IPM III – Design the Well Candidate
Sub Use Case(s):	N/A
Channel To Primary Actor:	N/A
Secondary Actor(s):	N/A
Channel(s) To Secondary Actor(s):	N/A

1. Business rules.

1.1. Inputs

Drill Pipe Size	–	Rig Constraint; Size of drill pipe available on the rig.
Weight On Bit (WOB)	–	Output of Bit Design.
Design Factor (DF)	–	Constant Value; 1.15 (or 1.4)
Buoyancy Factor (K_b)	–	Factor used to off set the weight adjustment for buoyancy added by the mud.
		Formula: $((65.44 - \text{Max Section Mud Weight}) / 65.44)$
Inclination (θ)	–	Maximum Angle of Inclination for the Bit Section.
BitSection _L	=	Maximum Depth of the Bit Section

5

1.2. Outputs

DC1 _L	–	Length of Drill Collar 1
DC1 _w	–	Weight of Drill Collar 1
DC1	–	Drill Collar 1 (Tubular)
DC2 _L	–	Length of Drill Collar 2
DC2 _w	–	Weight of Drill Collar 2
DC2	–	Drill Collar 2 (Tubular)
HW _L	–	Length of Heavy Weight Drill Pipe
HW _w	–	Weight of Heavy Weight Drill Pipe
HW	–	Heavy Weight Drill Pipe (Tubular)

1.3. Algorithm

10

1. Determine Outer Diameter DC1, DC2, HW and DP

a. DC1

- DC1_{OD} = Obtained from table by using the Hole Size (Bit Diameter)

Note: (Discussed with Daan)

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If there is more than one ID for the same OD, then the system will use the heaviest of them, which generally is the one with the smallest ID

b. DP

- Use Stiffness Ratio to Determine the Outer Diameter.

20

- DP_{OD} = Obtained from table by using the Hole Size (Bit Diameter)

- DP_{OD} ≤ DC1_{OD}

c. DC2

- Use Stiffness Ratio to Determine the Outer Diameter.

$$- SR = Z_{BIG}/Z_{SMALL}$$

$$- Z = (\pi/32) ((OD^4 - ID^4) / OD)$$

$$- SR < 3.5$$

$$- DC2_{OD} \leq DC1_{OD} \text{ \& } DC2_{OD} \geq DP_{OD}$$

d. HW

- Use Stiffness Ratio to Determine the Outer Diameter.

$$- SR = Z_{BIG}/Z_{SMALL}$$

$$- Z = (\pi/32) ((OD^4 - ID^4) / OD)$$

$$- SR < 3.5$$

$$- HW_{OD} \leq DC2_{OD} \text{ \& } HW_{OD} \geq DP_{OD}$$

$$e. DP_{OD} \leq HW_{OD}$$

2. Determine Weight of DC1, DC2 and HW.

When maximum hole angle is less than 65 degrees:

$$DC1_w = DC1_L * DC1_{WFT}$$

$$DC2_w = (DC1 + DC2) - DC1$$

When maximum hole angle is more than 65 degrees:

$$HW_w = \frac{WOB (DF)}{90ft \ K_b \ DC1_w} = WT \ DC1 * \cos(\theta)$$

$$DC1_w = DC1_L = 0$$

Determine Length of DC1, DC2, HW, DP

a. DC1

$$- DC1_L = 90 \text{ Feet} = 1 \text{ Stand} = 3 \text{ Joint}$$

b. DC2

$$- DC2_L = DC2_w / DC2_{WFT}$$

c. HW

$$- HW_L = HW_w / HW_{WFT}$$

d. DP

$$- DP_L = BitSection_L - (DC1_L - DC2_L - HW_L)$$

3. Tensile Risk

a. Take the rating of the top most Drill Pipe (for our purposes always use Premium 80%)

$$b. \text{ Tensile Risk} = ((\Sigma(W_{\text{Components}}) * K_b) + \text{Min. Overpull}) / (\text{Pipe Tensile Rating} * .8)$$

Note, the minimum and maximum hole sizes are given for PDM's in its catalog.

5 DS 1 Minimum overpull

Short Description	Define the minimum required overpull for a drill string										
Description	<p>The tensile strength of any pipe in the string may be exceeded by the weight of the string and a margin. This margin is used for the overpull in case the string is stuck and can be freed by pulling hard. Typically the minimum overpull required is 100,000 lbs (by default for 5" DP). Note that the weakest link in the string is not necessarily the pipe in the rotary table.</p> <p>Overpull</p> <table border="1"> <tr> <td>6 5/8"</td><td>125 klbs</td></tr> <tr> <td>5"</td><td>100 klbs</td></tr> <tr> <td>4 1/2"</td><td>75 klbs</td></tr> <tr> <td>3 1/2"</td><td>50 klbs</td></tr> <tr> <td>2 7/8"</td><td>35 klbs</td></tr> </table>	6 5/8"	125 klbs	5"	100 klbs	4 1/2"	75 klbs	3 1/2"	50 klbs	2 7/8"	35 klbs
6 5/8"	125 klbs										
5"	100 klbs										
4 1/2"	75 klbs										
3 1/2"	50 klbs										
2 7/8"	35 klbs										
Formula											
Score											

DS 2 Minimum torque strength

Rule	
Short Description	Define minimum torque strength for a drill string
Description	A drill string can part when the torque strength is exceeded due to high drag. Drag can be calculated and needs to be compared with the torque strength from a lookup table.
Formula	
Score	

DS 3 BHA components for directional section

Rule	
Short Description	Default BHA components for directional sections
Description	<ul style="list-style-type: none"> • A PDM is required to drill a directional section (Incl > 10 deg, DLS > 2 Deg/100ft) • A MWD tool is required for a directional section. • A LWD tool is optional for a directional section.
Formula	<p>Directional section = Incl > 10 deg</p> <p>Directional section = DLS > 2 deg/100ft).</p>

Score

DS 4 MWD is suggested in last hole section (production hole)

Rule	
Short Description	MWD is recommended in last hole section (production hole)
Description	A MWD is recommended during the last hole section of a non-directional well.
Formula	
Score	

DS 5 No BHA jewels (PDM,LWD,MWD) in surface holes.

Rule	
Short Description	No BHA jewels in surface holes.
Description	In a non directional well, by default) the conductor and surface casing will be rotary drilled (No PDM, MWD, LWD)
Formula	
Score	

5

DS 6 The LWD will always be run in the last hole section of a directional well

Rule	
Short Description	The LWD will always be run in the last hole section of a directional well
Description	The LWD will always (discussed with Daan) be run in the last hole section of a directional well
Formula	
Score	

DS8	PDM, MWD, LWD Costs
Short Description	When special BHA equipment is used – PDM, MWD, LWD, the cost should also be calculated and user should be able to edit.
Description	Most common costs for this equipment is variable cost per day per piece of equipment, however the individual costs change when run in combinations.
Formula	<p>These costs have to be calculated for each bit run that the equipment is used. There are two costs per piece of equipment – standby rate and usage rate. Standby rate is charged to all equipment for the duration of the hole section. This is increased to the usage rate when the equipment is in the hole (bit run duration).</p> <p>This may need to be calculated after the time estimate and only present</p>

the user with the rates in this task for modification purposes.

$$\text{Cost (\$)} = \text{Rate (\$/day)} * \text{Duration (days)}$$

Equipment	Usage rate (\$/day)	Standby rate (\$/day)
PDM	3500	500
MWD	2500	500
LWD	5000	500
PDM/MWD	5000	1000
MWD/LWD	7000	1000
PDM/MWD/LWD	10000	1500

Score

Display PDM type

Once the OD of DC1 is determined, the type of PDM needs to be displayed. By default,

- 5 the first PDM for a given size is selected. Select the PDM size closest to the DC1 OD, and select the largest PDM in case two PDM's are equally close to the required size.

Display in a dropdown list all available PDM's for that size, presenting the number of lobes and number of stages (merge cells if needed) including the OD.

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Size	OD	Lobes	Stages	dPtest	Qtest	M W	dP w/H2O	Min flow	Max flow	Rev/gal
A287	2.875	5/6	3.3	140	80	8.34	190	20	130	6
	2.875	5/6	7.0	194	80	8.34	244	20	130	5.8
	2.875	7/8	3.2	191	90	8.34	241	30	130	4.2
A350	3.5	4/5	5.0	138	100	8.34	188	30	160	3.3
	3.5	7/8	3.0	168	110	8.34	218	30	160	1.6
A475	4.75	4/5	3.5	115	250	8.34	165	100	350	1.1
	4.75	4/5	6.0	151	250	8.34	201	100	350	1.1
	4.75	7/8	2.2	170	250	8.34	220	100	350	0.6
A675	6.75	4/5	4.8	152	600	8.34	202	300	700	0.5
	6.75	4/5	7.0	184	600	8.34	234	300	700	0.5
	6.75	7/8	3.0	181	600	8.34	231	300	700	0.3
	6.75	7/8	5.0	210	600	8.34	260	300	700	0.3
A800	8	4/5	3.6	151	900	8.34	201	300	1100	0.3
	8	4/5	5.3	175	900	8.34	225	300	1100	0.3
	8	7/8	3.0	218	900	8.34	268	300	1100	0.2
	8	7/8	4.0	233	900	8.34	283	300	1100	0.2

A962	9.625	3/4	4.5	300	900	8.34	350	600	1500	0.2
	9.625	3/4	6.0	570	900	8.34	620	600	1500	0.2
	9.625	5/6	3.0	280	900	8.34	330	600	1500	0.1
	9.625	5/6	4.0	305	900	8.34	355	600	1500	0.1
A1125	11.25	3/4	3.6	395	1250	8.34	445	1000	1700	0.1

Kick tolerance calculation

Once the BHA configuration is determined, the kick tolerance will be calculated and displayed in the grid per hole section, next to each BHA configuration.

The following assumptions will be made:

- Use Ideal Gas equations
- Use standard temperature profile
- Calculate at section TD
- Use 0.1 psi/ft gas density (use input value)

Assumptions

Unless extensive and client-documented local experience exists indicating otherwise, the influx shall be deemed to be dry gas (0.7 specific gravity gas relative to air or 0.1 psi/ft). All calculations shall be based on the Driller's method of circulating out the influx (as this method results in the highest annular pressures when the effect of gas migration is disregarded in the Wait and Weight method).

For each relevant hole section, assume

- maximum expected pore pressure
 - minimum expected formation strength
 - maximum mud weight
1. The influx is at bottom.
 2. The influx will be circulated out using the Driller's Method.
 3. The pipe is on bottom.

Risk

Kick tolerance volume – Development wells	Kick tolerance volume – Exploration wells	Risk
>50 bbls / 8 m3	>100 bbls	Low
> 25 bbls and < 50 bbls	>35-100 bbls	Medium
< 25 bbls	<35 bbls	High

5 The invention being thus described, it will be obvious that the same may be varied in many ways. Such variations are not to be regarded as a departure from the spirit and scope of the invention, and all such modifications as would be obvious to one skilled in the art are intended to be included within the scope of the following claims.